REVISED

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR APPROVAL OF AN INFRASTRUCTURE INVESTMENT PROGRAM (JCP&L RELIABILITY PLUS)	**)))))))**	**BPU DOCKET NO. EO18070728**

DIRECT TESTIMONY OF
MAXIMILIAN CHANG AND CHARLES SALAMONE
ON BEHALF OF THE
DIVISION OF RATE COUNSEL

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PUBLIC VERSION

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I. STATEMENT OF QUALIFICATIONS

Q. Would the members of the Engineering Panel Review ("Panel") please state your names, positions, and business address.

A. My name is Charles Salamone, PE. I am Owner of Cape Power Systems Consulting, LLC a power systems consulting Company with an address of 630 Cumberland Dr., Flagler Beach, Florida and I am a subcontractor of Synapse Energy Economics, Inc. ("Synapse").

My name is Maximilian Chang. I am a Principal Associate with Synapse Energy Economics, an energy consulting company located at 485 Massachusetts Avenue, Cambridge, Massachusetts.

Q. On whose behalf are you submitting testimony in this proceeding?

A. We are submitting testimony on behalf of the New Jersey Division of Rate Counsel ("Rate Counsel").

Q. Mr. Salamone, please describe your education and professional background.

1. I hold a Bachelor of Science Degree in Electrical Engineering from Gannon University. I joined the Engineering Department of Commonwealth Electric Company in 1973. At that time, I became a Junior Planning Engineer where my primary responsibilities were to assist in the planning, analysis, and design of the transmission and distribution systems of Commonwealth Electric Company, later known as NSTAR. I generally followed the normal progression of positions with increasing levels of responsibility within the planning area until taking the position of Director of System Planning at NSTAR in 2000. I held that position

until starting Cape Power Systems Consulting, LLC in 2005. During my career with NSTAR, in addition to the responsibilities associated with overseeing System Planning, I served as Chair of the New England Power Pool ("NEPOOL") Planning Policy Subcommittee (1997-1998), Chair of the NEPOOL Regional Transmission Planning Committee (1998-1999), and Vice Chair of the NEPOOL Reliability Committee (1999-2000). As a consultant, I have been providing consulting services to a number of power system industry clients since 2005. I am a Registered Professional Engineer with the Commonwealth of Massachusetts. I am also a senior member of the Power Engineering Society of the Institute of Electrical and Electronic Engineers. A copy of my resume is attached hereto as **Attachment RC-ENG-1**.

Q. Mr. Salamone, have you previously testified before utility regulatory agencies?

A. Yes. I have previously testified before the New Jersey Board of Public Utilities ("BPU" or "Board"), the Federal Energy Regulatory Commission ("FERC"), the Massachusetts Department of Public Utilities, and the Massachusetts Energy Facilities Siting Board on a number of technical matters relating to ratemaking and system planning.

Q. Mr. Chang, please describe your professional background at Synapse Energy Economics.

A. My experience is summarized in my resume, which is attached as **Attachment RC-ENG-2**. I am an environmental engineer and energy economics analyst who has analyzed energy industry issues for ten years. In my current position at

Synapse Energy Economics, I focus on economic and technical analysis of many aspects of the electric power industry, including: (1) utility mergers and acquisitions, (2) utility reliability performance and distribution investments, (3) nuclear power, (4) wholesale and retail electricity markets, and (5) energy efficiency and demand response alternatives. I have been an author and project coordinator for the last two biennial New England Avoided Energy Supply Component reports, which were used by energy efficiency program administrators in the six New England states to evaluate energy efficiency programs.

Q. Mr. Chang, please describe your educational background.

A. I hold a Master of Science degree from the Harvard School of Public Health in Environmental Health and Engineering Studies, and a Bachelor of Science degree from Cornell University in Biology and Classical Civilizations.

Q. Mr. Chang, have you previously submitted testimony before the Board of Public Utilities?

A. Yes. I filed testimony before the Board in dockets GO12050363 (South Jersey Gas Energy Efficiency), EM14060581 (Exelon-PHI Merger), ER14030250 (RECO Storm Resiliency), and GM15101196 (AGL Southern Company Merger), ER17030308 (ACE Rate Case), ER18010029 (PSE&G Rate Case), and ER18020196 (ACE Infrastructure Investment Program).

Q. Mr. Chang, have you previously testified before utility regulatory agencies?

A. Yes. I have previously testified before the District of Columbia Public Service Commission, the Hawaii Public Utilities Commission, the Illinois Property Tax Appeal Board, the Maine Public Utilities Commission, the Maryland Public

Service Commission, and the Massachusetts Department of Public Utilities. I have also filed testimony before the Delaware Public Utilities Commission, the Kansas Commerce Corporation, the Illinois Commerce Commission, and the United States District Court for the District of Maine.

II. PURPOSE AND SUMMARY OF RECOMMENDATIONS

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our testimony is to review aspects of Jersey Central Power and Light's (the "Company" or "JCP&L") petition ("Petition") to seek approval from the New Jersey Board of Public Utilities (the "Board") for the implementation of their Infrastructure Investment Program ("JCP&L IIP"). As filed, the JCP&L IIP spending proposal amounts to $386.8 million over the next four years.

Q. Please summarize your findings and recommendations.

A. We find and conclude:

- We find that the majority of the proposed programs are continuation of programs already undertaken by the Company to maintain safe and reliable service and therefore should not receive accelerated recovery.
- The Company's benefit cost analysis is driven by the Enhanced Vegetation Management subprogram. With the exception of the Distribution Automation program, the other proposed programs are not cost-effective based on the Company's own analysis on a NPV basis.
- The Company's benefit cost analysis includes assumptions that overstate the benefits attributed to its proposed infrastructure investment program.

[Begin Confidential] [redacted] **[End Confidential]**

- The Company's proposed infrastructure investment program is not supported by detailed engineering reports for each of the projects as required under N.J.A.C 14:3-2A.5(b)(3). They only provide broad outlines of programs and does not provide individual project completion dates for a number of its proposed sub-programs.
- If the Board were to proceed with approval of JCP&L's IIP, notwithstanding the identified deficiencies, we recommend that the Company approve of a four-year program with a $97 million budget subject to the submittal of detailed engineering reports for the program. The $97 million budget reflects our recommended adjustments to the Company's proposal removing all of the Company's proposed subprograms with the exception of the Distribution Automation program.

III. INFRASTRUCTURE INVESTMENT PLAN REGULATION

Q. What is your understanding of the Infrastructure Investment Program Regulation within New Jersey?

A. It is our understanding that the Board adopted the Infrastructure Investment regulation ("IIP Regulation") to support distribution investments that go above and beyond "business as usual" distribution system spending.[1] In broad terms, the

[1] N.J.A.C 14:3-2A.1(a).

Board has indicated that qualifying projects would be eligible for accelerated investment and must enhance the reliability, resiliency and safety of the grid.[2] The IIP Regulation does not supplant an EDC's responsibility to maintain adequate spending for normal distribution operations.

Q. Would this make any project eligible under the IIP Regulation?

A. No, the IIP Regulation "encourages and supports necessary accelerated construction, installation, and rehabilitation of certain utility plants and equipment."[3] The phrase "certain" does not include all or most. As a result, we believe that the IIP Regulation is intended for those investments that would not likely occur without an accelerated cost recovery mechanism. Additionally, the Board's IIP Regulation clearly states that qualifying investments must be well supported as per the Board's minimum filing requirements in the form of engineering evaluations and cost benefit analyses justifying both their cost effectiveness and impact on the reliability and resiliency goals as established by the Board.[4] If the projects are deemed eligible and they meet the requirements set forth in the IIP Regulation, once approved by the Board, the IIP mechanism would allow the utility to accelerate these qualifying capital investments and obtain accelerated recovery for these investments.

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[2] N.J.A.C 14:3-2A.1(a).
[3] N.J.A.C. 14:3-2A.1(b).
[4] N.J.A.C. 14:3-2A.5(b)(3).

Q. As defined by the Board, what projects are eligible for accelerated cost recovery under the IIP Regulation?

A. Projects eligible under the accelerated cost recovery mechanism as established by the IIP Regulation must enhance safety, reliability and/or resiliency and must be non-revenue producing.[5] It is our understanding that program eligibility must be supported by engineering evaluations and cost benefit analyses to be provided by the utility.[6] Also, the projects eligible under the IIP must be incremental to the annual baseline spending levels established by the Board.[7]

Q. Please describe additional eligibility requirements of the regulation.

A. Another critical eligibility criterion of the IIP Regulation is the Board's requirement that:

> Only expenditures that are in excess of the annual baseline spending levels established by the Board and that meet the other requirements of this subchapter shall be eligible for accelerated recovery pursuant to N.J.A.C. 14:3-2A.6.

We believe that the Board incorporated this provision to ensure that eligible programs would not replace or supplant the Company's normal distribution spending to provide safe and reliable service to customers. Consequently, we do not think that the Board intended the Company to reduce baseline distribution infrastructure budgets and to shift normal reliability projects to the proposed infrastructure investment program.

[5] N.J.A.C. 14:3-2A.1(a).
[6] N.J.A.C. 14:3-2A.5(b).
[7] N.J.A.C. 14:3-2A.3(d).

IV. JCP&L INFRASTRUCTURE INVESTMENT PLAN

Q. Please summarize the Company's proposed IIP spending.

A. The Company is seeking Board approval to spend $386.8 million between 2019 through 2022 for its IIP. Witness Dennis Pavagadhi's direct testimony provides a summary of the Company's proposed IIP capital spending between 2019 - 2022. We have provided a tabular representation of the capital spending below:

Schedule 1 Proposed JCP&L IIP Program Budget for 2019-2022[8]

Program	Subprogram	Petition ($ millions)
Circuit Reliability and Resiliency	Lateral Fuse Replacement with TripSaver	$19.8
	Enhanced Vegetation Management	$108.0
	Install Back-up Generation	$5.1
Substation Reliability Enhancement	Substation Enhanced Flood Mitigation	$17.8
	Substation Equipment Replacement	$37.0
	Mobile Substations	$8.7
	Modernize Protective Equipment	$13.4
	Substation Fencing Enhancement	$9.1
Distribution Automation	Circuit Protection and Sectionalization	$11.5
	Install SCADA - Line Devices	$45.2
	Distribution Automation	$11.7
	RTU Upgrades in Substations & ADMS	$40.1
Underground System Improvements	Underground Cable Replacement	$44.9
	Submersible Transformer Replacement	$3.8
	Conventional and Network UG Rehab and Resiliency	$11.0
Total		**$386.8**

[8] Direct Testimony of Dennis Pavagadhi. July 13, 2018. Page 18, line 2 and Page 30, line 1.

The Company's proposed IIP spending is concentrated in four program categories detailed below:

1. **<u>Overhead Circuit and Reliability Program</u>:** This program is divided into three subprograms: (1) lateral fuse replacements, (2) enhanced vegetation management, and (3) install back-up generation.

<u>Lateral Fuse Replacement with TripSaver</u>

The Company will replace several thousand lateral fuses with TripSaver II cutout-mounted reclosers.[9] The manufacturer, S&C, advertises that the TripSaver II device is programmed to automate the reset process, restoring service to customers protected by that device after the momentary contact and the temporary fault is cleared.[10] The Company proports that the TripSaver II reclosers will clear temporary faults and avoid an extended outage that would have occurred with a fused lateral.[11] For the lateral fuse replacement program, the Company is proposing to spend $19.8 million on this subprogram over the four-year period.

<u>Enhanced Vegetation Management</u>

The Company also proposes to undertake a vegetation management capital project specifically targeting hazard trees, Ash tree removal, and overhang removal in Zone 2.[12] The Company touts that this initiative will target tree removal that is currently not covered by the standard 4-year tree trimming cycle.

[9] Direct Testimony of Dennis Pavagadhi. July 13, 2018. Page 21, lines 5-6.
[10] https://www.sandc.com/en/products--services/products/tripsaver-ii-cutout-mounted-recloser/ Accessed December 11, 2018.
[11] Direct Testimony of Dennis Pavagadhi. July 13, 2018. Page 21, lines 11-15.
[12] We understand that the Company defines Zone 1 as the portion of the circuit from the substation breaker to the first protective device and Zone 2 as the three-phase conductor and devices after the first protective device as noted in the Company's JCP&L Reliability Plus Engineering Evaluation and Report on Page 13.

The Company has indicated that the program will focus on Ash trees (impacted by the Emerald Ash Borer infestation), trees that are a weak structure tree species, or trees having split trunks, co-dominate stems, lightning or mechanical damage, or exposed roots.[13] The Company proposes to capitalize the proposed vegetation management expenses and spend approximately $108 million over the four-year life of the program. Given the size and impact of the proposed enhanced vegetation management program, we discuss the subprogram in more detail later in our direct testimony.

<u>Install Back-Up Generation</u>

The last component of the Company's proposed Circuit Reliability and Resiliency Program is the purchase and installation of back-up generators for the Company's line shops.[14] The Company proposes to spend approximately $5.1 million over the four-year life of the program.

2. **<u>Substation Reliability Enhancement</u>:** This program is divided into five subprograms: (1) Substation Enhanced Flood Mitigation, (2) Substation Equipment Replacement, (3) Mobile Substation Purchases, (4) Modernize Protective Equipment, and (5) Substation Fencing Enhancements.

<u>Substation Enhanced Flood Mitigation</u>

The Substation Enhanced Flood Mitigation work would add flood walls and automatic flood gates at nine substations that experienced flooding in prior

[13] Direct Testimony of Dennis Pavagadhi. July 13, 2018. Page 19, lines 8-14.
[14] Direct Testimony of Dennis Pavagadhi. July 13, 2018. Page 21, lines 16-19.

storms, and where the Company has added temporary flood walls.[15] As part of the proposed sub-program, the Company will also purchase high capacity pumps to remove water at 18 substations. The Company proposes to spend approximately $17.8 million over the four-year life of the program.

<u>Substation Equipment Replacement Program</u>

The Substation Equipment Replacement Program would replace distribution substation equipment such as breakers, transformers and switchgear across the Company's substations.[16] The Company proposes to spend approximately $37 million over the four-year life of the program.

<u>Mobile Substations</u>

As part of the proposed IIP program, the Company proposes to purchase one mobile substation during each year (i.e., four total mobile substations over the course of the IIP).[17] The Company proposes to spend $8.7 million for these purchases during the four-year period.

<u>Modernize Protective Equipment</u>

As part of the proposed IIP program, the Company proposes to replace existing substation relay equipment during the four-year program.[18] The Company proposes to spend $13.4 million for this replacement work.

<u>Substation Fencing Enhancement Initiative</u>

[15] Direct Testimony of Dennis Pavagadhi. July 13, 2018. Page 22, lines 8-11.
[16] Petition. Page 9.
[17] Petition. Page 9.
[18] Petition. Page 9.

The last subprogram in the Substation Reliability Enhancement program is the Company's Substation Fencing Enhancement Initiative. For this subprogram, the Company proposes to install high security fencing at distribution substations across its service territory.[19] The Company proposes to spend $9.1 million for this subprogram during the four-year period of the IIP.

3. <u>Distribution Automation:</u> This program is divided into four subprograms: (1) Circuit Protection and Sectionalization, (2) Install SCADA- Line Devices, (3) Distribution Automation, and (4) RTU Upgrades in Substations and ADMS.

<u>Circuit Protection and Sectionalization</u>

The proposed Circuit Protection and Sectionalization subprogram would replace fuses on 4.8kV circuits with electronic reclosers and supervisory control and data acquisition ("SCADA") control across the Company's service territory over the next four years.[20] The Company proposes to spend $11.5 million for this subprogram during the four-year period of the IIP.

<u>Install SCADA - Line Devices</u>

The proposed install SCADA-line devices subprogram would replace existing reclosers with upgraded reclosers and install communications equipment for SCADA across the Company's service territory over the next four years.[21] The Company proposes to spend $45.2 million for this subprogram during the four-year period of the IIP.

<u>Distribution Automation Subprogram</u>

[19] Petition. Page 9.
[20] Petition. Page 9.
[21] Petition. Page 9.

The proposed Distribution Automation subprogram would construct distribution automatic loop schemes with reclosers and SCADA control for real time system monitoring and remote control capability.[22] The Company proposes to spend $11.7 million for this subprogram during the four-year period of the IIP.

RTU Upgrades in Substations and ADMS

The last subprogram in the Distribution Automation program is the Company's remote terminal unit ("RTU") and advanced distribution management system ("ADMS") upgrades. For this subprogram, the Company proposes to implement an ADMS and to install load voltage and data monitoring points to gather circuit level data at its substations.[23] The Company proposes to spend $40.1 million for this subprogram during the four-year period of the IIP.

4. Underground System Improvements This program is divided into three subprograms: (1) Underground Cable Replacement, (2) Submersible Transformer Replacement, and (3) Conventional and Network UG Rehab and Resiliency.

Underground Cable Replacement

The proposed Underground Cable Replacement subprogram would replace underground bare concentric neutral cable with new jacketed cable and replace associated underground switches and pad-mounted transformers across the Company's service territory.[24] The Company proposes to spend $44.9 million for this subprogram during the four-year period of the IIP.

Submersible Transformer Replacement

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[22] Petition. Page 9.
[23] Petition. Page 9.
[24] Petition. Page 10.

The proposed Submersible Transformer Replacement subprogram would replace underground submersible transformers with pad-mounted transformer across the Company's service territory.[25] The Company proposes to spend $3.8 million for this subprogram during the four-year period of the IIP.

<u>Conventional and Network Underground Rehab and Resiliency</u>

The last subprogram in the Underground System Improvement program is the Company's Conventional and Network UG Rehab and Resiliency. For this subprogram, the Company proposes to reinforce and rehabilitate underground network ducted distribution system and conventional ducted distribution system consisting of vaults, manholes, covers, duct, cable, transformers and switches.[26] The Company proposes to spend $11 million for this subprogram during the four-year period of the IIP.

V. MINIMUM FILING REQUIREMENTS FOR IIP PROGRAMS

Q. Does the IIP Regulation mandate minimum filing requirements for IIP petitions?

A. Yes, in addition to supplemental information that may be required by the Board detailed in <u>N.J.A.C.</u> 14:3 2A.5(b). The minimum filing requirements to be filed as part of an IIP petition include:

1. Projected annual capital expenditure budgets for a five-year period, identified by major categories of expenditures;
2. Actual annual capital expenditures for the previous five years, identified by major categories of expenditures;

[25] Petition. Page 10.
[26] Petition. Page 10.

3. An engineering evaluation and report identifying the specific projects to be included in the proposed Infrastructure Investment Program, with descriptions of project objectives-including the specific expected resilience benefits, detailed cost estimates, in service dates, and any applicable cost-benefit analysis for each project;
4. An Infrastructure Investment Program budget setting forth annual budget expenditures;
5. A proposal addressing when the utility intends to file its next base rate case, consistent with N.J.A.C. 14:3-2A.6(f);
6. Proposed annual baseline spending levels, consistent with N.J.A.C. 14:3-2A.3(a) and (b);
7. The maximum dollar amount, in aggregate, the utility seeks to recover through the Infrastructure Investment Program; and
8. The estimated rate impact of the proposed Infrastructure Investment Program on customers.[27]

The Company's Petition would thus need to conform to these requirements for the Board to consider the eligibility of the JCP&L IIP projects.

Q. Did JCP&L's IIP petition meet the minimum filing requirements as required by the Board?

A. No. The Company's petition was deficient in several respects. First, the Company's petition did not include a detailed engineering evaluation and report identifying specific projects as required by N.J.A.C. 14:3-2A.5(b)3. The Company's petition included a 286-page attachment ("Engineering Evaluation and Report" or "Appendix B") that provided proposed project locations for a number of individual subprograms for the period 2019-2022.[28] However, the body of Appendix B contained a 30-page summary discussion of JCP&L's proposed IIP program. The remainder of Appendix B simply listed individual circuits and sub-program locations. Appendix B did not detail specific needs analyses or

[27] N.J.A.C. 14:3-2A.5(b)
[28] JCP&L Reliability Plus Engineering Evaluation and Report. Direct Testimony of Dennis Pavagadhi Appendix B. July 13, 2018.

alternatives for any individual project. Consequently, we do not believe that Appendix B qualifies as an "engineering report" since there were no detailed analyses provided for any of the individual projects proposed.

Q. What would an appropriate engineering report look like?

A. N.J.A.C. 14:3-2A.5(b)(3) described the content of an accompanying engineering evaluation and report that would be part of an IIP Regulation petition. Specifically, the language of the Regulation states:

> An engineering evaluation and report identifying the specific projects to be included in the proposed Infrastructure Investment Program, with descriptions of project objectives-including the specific expected resilience benefits, detailed cost estimates, in service dates, and any applicable cost-benefit analysis for each project.[29]

We identify several areas that were lacking as described below:

Identify Specific Projects: Merely listing the project name for Enhanced Vegetation Management, Substation Reliability, Mobile Substation, Distribution Automation does not provide the necessary information to evaluate the justification and/or analysis behind the project. For these blanket projects, the Company only provided a broad overview of the program objective and benefits in its filing.

Alternatives Analysis: For the substation flood mitigation analysis, the Company's Appendix B should have contained detailed engineering evaluations for each of the eleven substations under this subprogram. For the blanket programs (i.e. lateral trip saver, enhanced vegetation management, substation equipment, underground), the Company should have, at a minimum, provided a

[29] N.J.A.C. 14:3-2A.5(b)(3).

detailed analysis of a representative project for each of the subprograms. In addition, a complete engineering analysis would explain how the Company would prioritize the implementation of each of the proposed sub-programs with justification of why specific projects were included and excluded.

Detailed Project Costs: The Company provided inconsistent individual project costs. For example, the Company provided detailed costs for individual TripSaver II fuse replacements and approximate completion dates for 2019, yet did not provide individual project costs for the subprogram for 2020-2022.[30] For other subprograms, the Company did not provide any estimated individual project costs. For example, the proposed Enhanced Vegetation Management program only identified targeted locations with no associated project costs.

Q. Why is a complete engineering analysis important?

A. We believe that a complete engineering report is critical to the IIP program since it provides the basis for the justification and prioritization of any adopted IIP. A complete engineering report also provides documentation of the baseline assumption, timing, and costs of the projects. Furthermore, this information will be critical at the close-out of the program to determine if the Company accomplished what it proposed at the outset of the program.

[30] Appendix B, Pages 80-130.

VI. HISTORICAL DISTRIBUTION CAPITAL SPENDING TO ESTABLISH BASELINE SPENDING

Q. Please summarize your recommendations regarding the Company's proposed baseline spending.

A. We find that the Company's projected average total distribution spending for 2019-2022 is $202 million compared to its historical average total distribution spending which is $194 million.[31] The Company's projected Total Distribution spending appears to be consistent with historical Total Distribution spending.[32] We recommend that the annual baseline spending levels should be established based on five years of historical capital spending.

Q. Does the Regulation establish baseline spending requirements?

A. The IIP Regulation requires the establishment of baseline spending levels under N.J.A.C. 14:3-2A.3(b) and requires infrastructure program spending to be incremental to baseline spending in N.J.A.C. 14:3-2A.3 (d). The language of N.J.A.C. 14:3-2A.3(b) lists a number of items which might be relevant to base line spending levels:

> In proposing annual baseline spending levels, the utility shall provide appropriate data to justify the proposed annual baseline spending levels, which may include historical capital expenditure budgets, projected capital expenditure budgets, depreciation expenses, and/or any other data relevant to the utility's proposed baseline spending level.

Additionally, the language of N.J.A.C. 14:3-2A.3(d) states:

> Only expenditures that are in excess of the annual baseline spending levels established by the Board and that meet the other requirements of

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[31] Direct Testimony of Dennis Pavagadhi. July 13, 2018. Schedule DP-2.
[32] We included projected 2018 spending as part of historical spending.

this subchapter shall be eligible for accelerated recovery pursuant to N.J.A.C. 14:3-2A.6.

The Company's proposed Total Distribution Capital budgets presented in Schedule DP-2 appear to be consistent with the Board's IIP Regulation.

Q. Does the Company provide a summary of historical baseline spending in its Petition?

A. Yes, JCP&L Witness Dennis Pavagadhi's direct testimony provides a summary of the Company's historical capital spending through 2017. The Company's overall distribution capital spending are presented below.[33]

Schedule 2 JCP&L Historical Distribution Capital Spending[34]

	2013	2014	2015	2016	2017	2018
Metering	$ 3,511,323	$ 9,557,573	$ 8,684,953	$ 6,353,165	$ 5,227,588	$ 5,997,837
Other	$ 26,614,703	$ 11,741,883	$ 21,596,120	$ 2,236,139	$ 6,282,655	$ 290,834
Replacements & Improvements	$ 41,790,206	$ 77,918,555	$ 69,752,522	$ 69,740,591	$ 70,218,984	$ 64,171,274
Vegetation Management	$ 7,264,569	$ 14,075,284	$ 13,251,603	$ 12,447,966	$ 12,777,019	$ 21,200,248
Reliability	$ 12,628,563	$ 32,815,760	$ 25,092,479	$ 25,598,458	$ 17,093,356	$ 36,030,661
Street Lighting	$ 6,537,720	$ 7,418,273	$ 6,155,755	$ 5,980,031	$ 6,177,456	$ 11,221,624
System Reinforcements	$ 6,936,747	$ 13,351,075	$ 8,710,174	$ 7,067,841	$ 6,572,484	$ 4,060,580
Facilities	$ 471,848	$ 880,785	$ 2,362,541	$ 2,178,677	$ 9,653,947	$ 843,148
Tools & Equipment	$ 1,472,189	$ 4,566,009	$ 3,745,250	$ 1,716,197	$ 2,548,511	$ 3,658,908
Total Base Capital	$ 107,227,868	$ 172,325,199	$ 159,351,397	$ 133,319,066	$ 136,552,001	$ 147,475,114
Damage Claims	$ 6,610,309	$ 8,878,243	$ 3,758,234	$ 5,095,480	$ 4,531,516	$ 1,606,936
Joint Use	$ 318,686	$ 1,959,592	$ 2,668,493	$ 1,644,550	$ 519,163	$ 1,116,606
New Business	$ 20,700,005	$ 38,228,291	$ 36,127,765	$ 42,018,410	$ 37,721,964	$ 34,300,409
Relocations	$ 4,578,829	$ 545,995	$ 2,483,689	$ 2,172,469	$ 1,931,381	$ 2,529,457
Storms	$ 23,574,103	$ (13,212,557)	$ 1,402,760	$ 22,429,556	$ 9,751,141	$ 4,080,034
Total Other Than Base Capital	$ 55,781,933	$ 36,399,564	$ 46,440,941	$ 73,360,465	$ 54,455,164	$ 43,633,442
Total Distribution	**$ 163,009,800**	**$ 208,724,763**	**$ 205,792,337**	**$ 206,679,531**	**$ 191,007,165**	**$ 191,108,556**

[33] Direct Testimony of Dennis Pavagahdi. Schedule DP-2. As noted, we have included projected 2018 spending as part of the historical spending for purposes of our analysis
[34] Direct Testimony of Dennis Pavagahdi, Schedule DP-2

Schedule 2 shows the breakdown of the capital spending categories as defined by the Company. Overall, the Company's total distribution base capital spending has generally increased since 2013. The Company's five-year (2013-2017) annual total distribution capital spending average is $195 million. The Company's historical average is slightly lower ($194 million) when the 2018 projected spending is included. We have included expenditures several categories: damage claims, joint use, new business, relocations, and storm. We recognize that these costs will fluctuate from year-to-year and are less reflective of planned operations.

Q. Does the Company provide a projected baseline spending amount in its Petition for the period 2019-2022?

A. Yes, the Company provided projected baseline capital expenses for the period 2019-2022 in the direct testimony of Dennis Pavagadhi. The proposed projected baseline spending is presented in the schedule below.

Schedule 3 JCP&L's Projected Distribution Spending Categories[35]

	2019	2020	2021	2022
Metering	$ 6,166,549	$ 6,595,985	$ 6,684,718	$ 6,894,436
Other	$ 3,130,940	$ 4,973,208	$ 682,922	$ 18,258,480
Replacements & Improvements	$ 54,518,868	$ 60,408,007	$ 62,035,292	$ 63,192,568
Vegetation Management	$ 20,142,320	$ 24,640,886	$ 25,099,279	$ 24,370,329
Reliability	$ 42,247,453	$ 36,923,105	$ 34,661,378	$ 36,069,087
Street Lighting	$ 11,080,349	$ 11,435,071	$ 11,572,940	$ 12,063,430
System Reinforcements	$ 1,093,596	$ 8,792,920	$ 7,516,954	$ 7,598,165
Facilities	$ 3,223,548	$ 1,027,856	$ 952,874	$ 892,526
Tools & Equipment	$ 3,297,897	$ 3,403,235	$ 5,406,562	$ 5,406,287
Total Base Capital	$ 144,901,520	$ 158,200,272	$ 154,612,918	$ 174,745,308
Damage Claims	$ 1,728,885	$ 2,061,312	$ 2,020,277	$ 2,241,823
Joint Use	$ 1,247,826	$ 1,207,508	$ 1,139,690	$ 1,212,417
New Business	$ 31,690,294	$ 34,204,537	$ 33,892,889	$ 35,548,822
Relocations	$ 2,545,249	$ 2,899,269	$ 2,797,743	$ 2,921,055
Storms	$ 4,231,074	$ 4,344,907	$ 4,640,998	$ 4,867,355
Total Other Than Base Capital	$ 41,443,327	$ 44,717,533	$ 44,491,597	$ 46,791,472
Total Distribution	**$ 186,344,848**	**$ 202,917,805**	**$ 199,104,515**	**$ 221,536,779**

On a five-year average basis, the Company is proposing future baseline spending of $202 million inclusive of several categories including damage claims, joint use, new business, relocations, and storm. We find that the proposed future total distribution baseline spending is consistent with historical spending.

Q. Does the Company's Petition include an overall distribution capital budget projection including both JCP&L's IIP costs and baseline spending?

A. No, the Company only provides an overall projected base distribution spending summary for 2018-2022.[36] We have provided a summary of the Company's

[35] Direct Testimony of Dennis Pavagahdi, Schedule DP-2

projected budget in the following schedule that include both baseline and IIP spending. We present the 2019-2022 projected total IIP costs and baseline spending based on the Company's categorizations in the following schedule:

Schedule 4 Summary of JCP&L Baseline and Proposed IIP Spending[37]

	2019	2020	2021	2022
Total Distribution Spending	$185,635,258	$202,917,805	$199,104,515	$221,536,779
Total IIP Spending	$89,186,659	$101,580,000	$99,610,000	$96,436,000
Total IIP and Distribution Spending	**$274,835,258**	**$304,517,805**	**$298,704,515**	**$317,936,779**

The above schedule shows the total distribution spending split among the components of the Company's proposed total distribution spending and the Company's proposed IIP spending. The schedule shows that JCP&L's proposed IIP would comprise 30 to 33 percent of the Company's projected annual distribution capital spending depending on the year. Over the entire 2019-2022 period, the Company's IIP program would represent 32 percent of the Company's total distribution capital spending.

VII. ENHANCED VEGETATION MANAGEMENT

Q. Please summarize your concerns regarding the Company's proposed enhanced vegetation management program.

A. We are concerned about the Company's proposed recovery mechanism and scope of the program in light of the fact that the Company has yet to complete a full trimming cycle under the Board's 2016 Vegetation Management requirements.[38]

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[36] The Company provided a summary of its projected spending, which we presented in Schedule 3 and restated in RCR-E-93, but did not include the incremental impacts associated with the proposed IIP.
[37] RCR-E-93 Attachments A & B

Q. Has the Company provided a detailed breakdown of the proposed Enhanced Vegetation Management Program?

A. Yes, the Company provided a breakdown of its proposed Enhanced Vegetation Management program, which is summarized below.[39]

Schedule 5 Detailed Capital Spending of Proposed Enhanced Vegetation Management Program

Year	Cost of Ash Removal	Cost of Hazard Tree Removal	Zone 2 Overhang Removal	Totals
2019	$ 10,789,094	$ 5,385,130	$ 11,570,081	**$ 27,744,306**
2020	$ 10,538,568	$ 5,219,708	$ 12,530,061	**$ 28,288,338**
2021	$ 10,773,295	$ 5,150,912	$ 10,189,153	**$ 26,113,361**
2022	$ 10,594,326	$ 4,819,338	$ 10,456,227	**$ 25,869,891**
Totals	**$ 42,695,284**	**$ 20,575,089**	**$ 44,745,523**	**$ 108,015,896**

The Company's proposed vegetation management subprogram would primarily focus on the removal of Ash trees, Hazard trees, and Zone 2 overhang over the course of the next four years.

Q. Do you have any concerns regarding the Company's Ash tree removal program?

A. We are concerned not about the need to remove Ash trees that have been afflicted with the Emerald Ash borer, but with the need to designate such a specific program beyond the Company's routine requirement to remove "Hazard" trees. It is an unfortunate fact that there will always be some infestation that will afflict trees. The New Jersey Department of Environmental Protection lists a number of

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[38] N.J.A.C 14:5-9.
[39] S-JCP&L-INF-10

pests and diseases that are afflicting trees across the state.[40] These include: (1) Asian Longhorned Beetle, (2) Bacterial Leaf Scorch, (3) Emerald Ash Borer, (4) Gouty Oak Gall, (5) Gypsy Moth, (6) Hemlock Woolly Adelgid, (7) Oak Wilt, (8) Southern Pine Beetle, and (9) Verticillium Wilt. The Company has only started to track Ash tree removals separately in 2017.[41] Thus, we see the Ash tree removal subprogram falling under the Company's historical "Hazard" tree removal process.

Q. Are tree related outages an issue for the Company?

A. We agree that the tree-related outages represent a major category of outage causes for the Company. Figure 1 shows historical JCP&L Tree Related Outages (excluding major events) compared to all outages. Outage data provided by JCP&L show tree related outages have historically represented 22 percent of all outages.[42] From 2015 through 2017 tree related outages were 17, 27, and 25 percent of all outages respectively.[43] The proposed Enhanced Vegetation Management will help reduce tree-related outages, but the program will not eliminate all tree-related outages.

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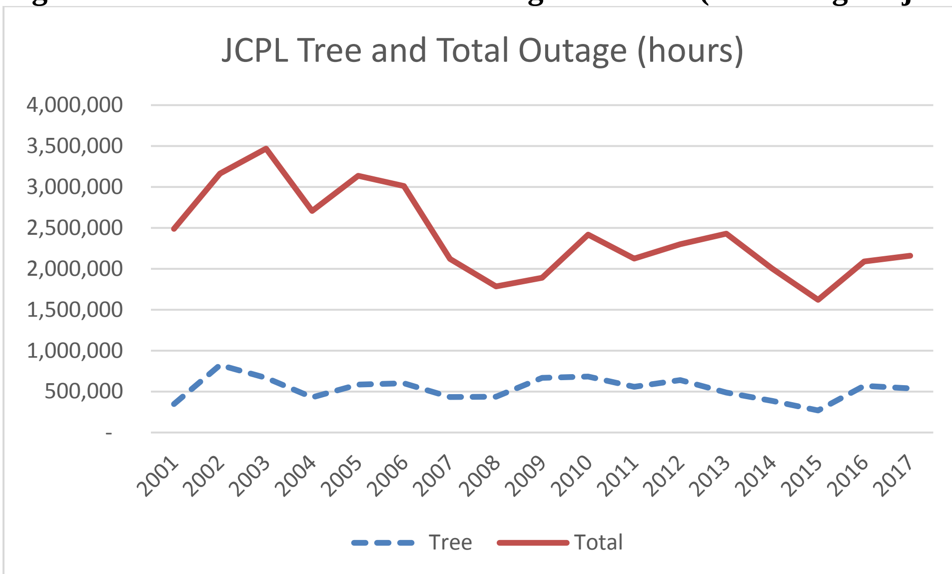
[40] https://www.state.nj.us/dep/parksandforests/forest/community/Verticillium_Wilt.htm. Accessed December 11, 2018.
[41] RCR-E-72
[42] RCR-E-6, Attachments A and H.
[43] Ibid.

Figure 1 JCP&L Historical Tree-Outage Duration (Excluding Major Events)

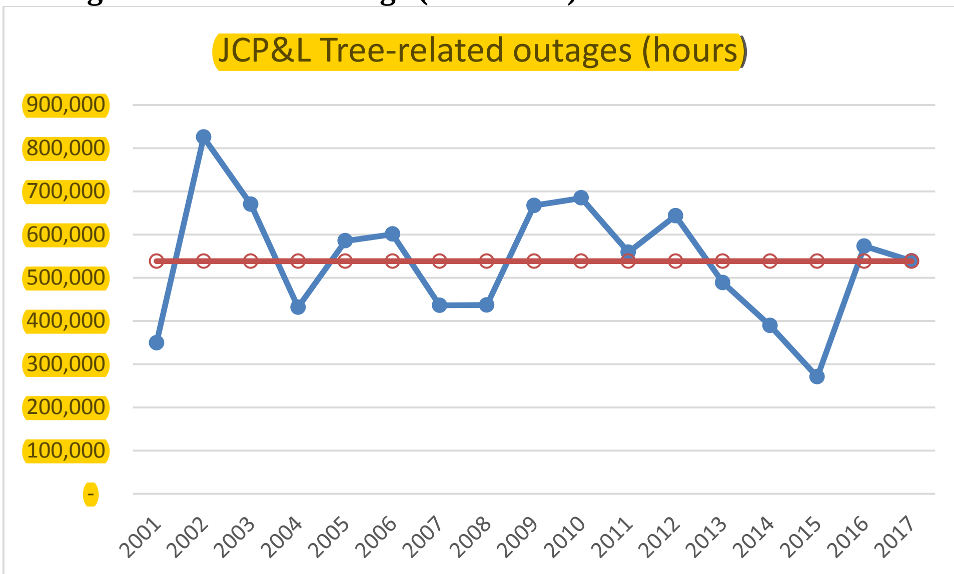


Q. How does the Company's recent tree-related outages compare to historical average?

A. The Company contends that one of the primary justifications for the Enhanced Vegetation Management program are recent trends in tree-related outages.[44] In Figure 2 below, we have charted the Company's (2001-2017) historical tree outage durations against the average annual tree related outage duration of 538,292 hours.[45]

[44] Direct Testimony of Dennis Pavagadhi, July 13, 2018. Page 20. Lines11-19.
[45] RCR-E-6 Attachment A, Page 16 and Attachment H, Page 16.

Figure 2 JCP&L Historical Tree Related Outage Duration Compared to Average Tree Related Outage (2011-2017)[46]



The data indicates that 2016 and 2017 were about average compared to historical outages. However, the most recent two years follow a period of relatively low reported tree-related outages in 2013, 2014 and 2015. This may be the result of major events that enabled the Company to exclude tree-related outage from the BPU's Annual System Performance Report.

Q. Has the Board undertaken steps to address tree-related outages across electric distribution companies throughout the state?

A. Yes. It is our understanding that the Company's current Vegetation Management program adheres to the revised regulations adopted by the Board in 2016. The BPU vegetation management regulations include:[47]

- Four-year trim cycle.

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[46] Ibid.
[47] N.J.A.C 14:5-9

- Hazard tree identification and management program.
- The removal of overhanging vegetation from the substation to the first protective device starting in January 2016.
- Additional reporting requirements for vegetation management.

Apart from reporting requirements and explicitly defining the trim area of distribution lines, it appears that the Company has already implemented the policies outlined in the BPU's vegetation management regulations.[48]

Q. Has the Company been able to determine the impacts of the Board's vegetation management regulations across the entirety of its service territory?

A. No, simply because the Company has yet to complete an entire four-year trim cycle under the Board's 2016 regulations. The Company's vegetation management expenses have only recently begun to show accelerated spending as summarized below.[49] The Company indicates that its current practices are in compliance with the Board's regulations.[50]

[48] RCR-E-37.
[49] We understand that the Company treats tree trimming within the established 15-foot corridor as expenses. The Company treats tree trimming beyond the 15-foot clearance corridor or tree removal as capital expenses.
[50] RCR-E-95.

Q. Has the Company provided its proposed vegetation management budgets?

A. Yes, we have summarized the Company's historical and projected capital spending for vegetation management below based on data provided by the Company.[51]

Figure 3 JCP&L Historical and Projected Vegetation Management Capital Spending (000's)[52]

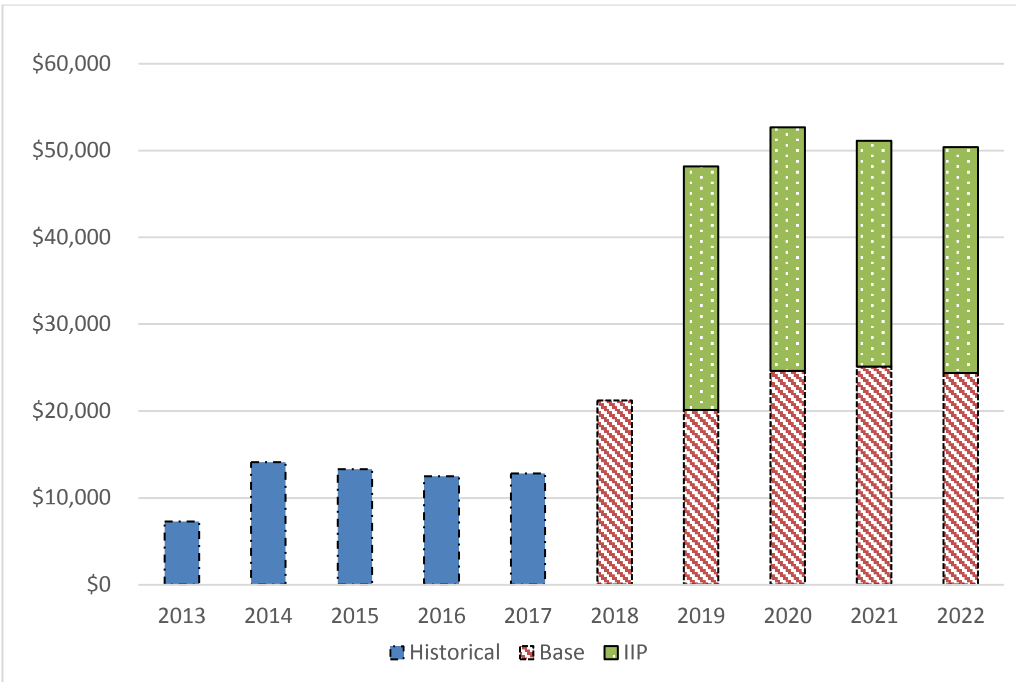

Figure 3 above graphically illustrates the dramatic spending on vegetation management proposed by the Company. The proposed baseline and IIP vegetation management spending averages to be about $50.5 million per year ($23.5 million for just future base vegetation management capital) between 2019 to 2022 compared to the Company's historical (2013-2018) average annual vegetation

[51] Schedule DP-2 (RCR-E-93 Attachment B) and JCP&L Reliability Plus Engineering Evaluation and Report (Page 11).
[52] Schedule DP-2 (RCR-E-93 Attachment B).

management spending has been $13.5 million per year. The Company has not provided any information as to how it will control costs or manage the dramatic increase in spending for vegetation management. Nor has the Company indicated that it will accelerate trimming cycles or the miles trimmed as part of its proposed the Enhanced Vegetation Management program.

Q. In addition to capital spending has the Company provided operations and maintenance expenses for tree trimming?

A. Yes, the Company's historical vegetation management expenses are provided below.

Schedule 6 JCP&L Historical Vegetation Management Expenses[53]

	2013	2014	2015	2016	2017
JCP&L O&M Distirbution Forestry	$12,170,512	$9,211,420	$10,676,172	$9,662,687	$15,462,350
VMS Deferral			($654,409)	($439,411)	($3,239,197)
JCP&L O&M Forestry Net of Deferral	**$12,170,512**	**$9,211,420**	**$10,021,763**	**$9,223,276**	**$12,223,153**

The Company has also indicted that future vegetation management expenses are not known at this time.[54]

Q. What are your concerns regarding the substantially increased vegetation management capital budgets?

A. As proposed, the Company's vegetation management capital would quadruple at the same time that other New Jersey EDCs are also increasing vegetation management spending. The Company has not provided documentation as to how it would manage such a dramatic increase in spending, nor has the Company

[53] S-JCP&L-INF-14.
[54] RCR-E-63.

outlined a specific plan to manage the increased spending other than how it treats vegetation management normally.[55] Based on the historical distribution spending for removal of ash and hazard trees, the spending per tree between 2013 and 2018 was $3,460 per tree.[56] If the Company were to proceed with its Enhanced Vegetation Management program, we would expect the Company to adhere to its historical per tree spending.

VIII. BENEFIT COST ANALYSIS CONCERNS

Q. Please summarize your concerns regarding the Company's benefit cost analysis.

A. Our concerns regarding the Company's benefit cost analysis are summarized below:

- The Company's own benefit cost analysis found its Substation Reliability Enhancement and Underground System Improvement programs are not cost-effective under a net present value evaluation.
- Removing the Company's Enhanced Vegetation Management subprogram reduces the overall IIP program's benefit cost ratio from **[begin confidential]** [redacted] **[end confidential]**. This suggests the Company's IIP petition is essentially a vegetation management program since the remaining IIP program cost-effectiveness is marginal with the removal of the Enhanced Vegetation Management Program.

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[55] S-JCP&L-RP-ACC-10
[56] RCR-E-72, Attachment A

- The Company includes the impact of **[begin confidential]** [redacted] **[end confidential]** in its calculations. This may overstate the benefits attributable to its proposed IIP program.
- The Company includes benefits for **[begin confidential]** [redacted] **[end confidential]** years that extends the period of analysis.

Q. Please summarize the Company's benefit cost analysis.

A. N.J.A.C. 14:3-2A.5(b)3 requires the Company to provide an "applicable" benefit cost analysis for each project as part of its IIP petition. The Company's benefit cost results on a net present value basis are summarized below:[57]

Schedule 7 Company's Benefit Cost Analysis ($ millions)[58]

	Nominal ($ in millions)			NPV ($ in millions)		
Customer Benefit Category	**Benefits**	**Costs**	**Benefit/Cost Ratio**	**Benefits**	**Costs**	**Benefit/Cost Ratio**
Circuit Reliability & Resiliency	$1,085	$133	8.2	$649	$112	5.8
Substation Reliability Enhancement	$196	$90	2.2	$62	$75	0.8
Distribution Automation	$388	$115	3.4	$125	$95	1.3
Underground System Improvements	$30	$62	0.5	$10	$52	0.2
Total IIP	**$1,698**	**$400**	**4.2**	**$846**	**$335**	**2.5**

The Company's analysis indicates that the overall program is cost effective with a benefit cost ratio of 2.5 on a net present value basis that discounts the costs and benefits using the Company's weighted average cost of capital ("WACC").[59]

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[57] The net present value presents the Company's IIP program using discounted cash flows to account for the time value of money. The Company's nominal analysis does not make the time value of money adjustment. For purposes of evaluating the Company's IIP program, we use the discounted values.
[58] Direct Testimony of Dennis Pavagadhi. July 13, 2018. Appendix B. JCP&L Reliability Plus Engineering Evaluation and Report. Page 28.
[59] We do not opine the appropriateness of the Company's WACC.

Q. Is there a significance to the Regulations' requirement: "any applicable cost-benefit analysis for each project"?

A. Yes. It is our interpretation that the Board requires each project to demonstrate its cost-effectiveness. As a result, a company cannot simply design an IIP program that has one sub-program that is very cost-effective to mask other sub-programs that are not cost-effective. We believe that each sub-program needs to demonstrate that it is cost-effective to be included in an approved IIP program.

Q. What is the impact of the Enhanced Vegetation Management program on the overall IIP program?

A. The Company's presentation of its benefit cost analysis incorporates the Enhanced Vegetation Management subprogram as part of the overall Circuit Reliability and Resiliency Program.[60] In order to isolate the impact of just the Enhanced Vegetation Management program, we adjusted the sub-program in the workbooks provided by the Company.[61] When we removed the benefits and costs of the enhanced vegetation management program, the remaining IIP program's benefit cost ratio decreases from 2.5 to **[Begin Confidential]** [redacted] **[End Confidential]** on a NPV basis. As we have stated earlier, each of the sub-programs need to be cost-effective. The Company's Substation Reliability Enhancement and Underground System Improvements program are not cost-effective on a stand-alone basis.

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[60] Direct Testimony of Dennis Pavagadhi. July 13, 2018. Appendix B. JCP&L Reliability Plus Engineering Evaluation and Report. Page 28.

[61] S-JCP&L-RP-ACC-04 CONFIDENTIAL Attachment A.

Q. Is the observation that the Company's Overhead Circuit Reliability and Resiliency program is shown to be cost-effective, justification for approving the entire IIP program?

A. No. Each program and subprogram should be cost-effective. While the Company's inputs suggest that the overall IIP program is cost-effective, we have already commented that the Company's proposed Enhanced Vegetation Management subprogram may not be achievable given the scope and timing of the investments in light of historical spending. We note below that the Company's TripSaver II subprogram continues investments already undertaken by the Company. Notably, the Company has not categorized the TripSaver II as a distribution automation program since the devices generally are standalone products that still require linemen to manually reset the recloser if the recloser ultimately trips.[62] Also, as we have stated earlier, the Company's own analysis shows that the Substation Reliability Enhancement and Underground System Improvement programs are not cost-effective. This would suggest that any approved IIP program should be based solely on elements of the Distribution Automation sub-program that appear to be cost-effective.

Q. Do you have concerns regarding the inclusion of major events as part of the overall storm benefits?

A. Yes, major events should be included as part of the benefit cost analysis. **[Begin Confidential]** [redacted]

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[62] https://www.sandc.com/en/products--services/products/tripsaver-ii-cutout-mounted-recloser/. Accessed December 12, 2018.

[redacted].[63] [redacted] **[End Confidential]**

Q. What should the Company have done?

A. **[Begin Confidential]** [redacted]. **[End Confidential]**

Q. Do you have concerns regarding the inclusion of [Begin Confidential] [redacted] **[End Confidential] as part of the overall storm benefits?**

A. The Company uses the **[Begin Confidential]** [redacted].[64] [redacted] **[End Confidential]**

Q. Did you adjust the Company's analysis to reduce the number of years?

A. Yes, when we reduce the analysis period to a **[Begin Confidential]** [redacted] **[End Confidential]**, it reduce the Company's benefit cost analysis results

[63] RCR-E-109 Confidential.
[64] RCR-E-106. Confidential

from 2.5 to **[Begin Confidential]** [redacted] **[End Confidential]** without changing any other assumptions.

Q. What would the Company's benefit cost ratio be if you removed the Enhanced Vegetation Management Program and adjusted the analysis period?

A. When we removed the Enhanced Vegetation Management Program and **[Begin Confidential]** [redacted]. **[End Confidential]**

IX. RATE COUNSEL ADJUSTMENTS TO IIP

Q. What are your recommended adjustments to the JCP&L IIP?

A. As detailed below, we recommend that the Board approve a four-year $97 million IIP for the Company. Our adjustments to the Company's proposed $386.8 million program exclude many projects that should be considered regular and routine distribution spending of the sort historically and typically recovered through base rates and are not cost effective.

Q. Please describe the process you followed to determine what projects should be excluded in the JCP&L IIP.

A. Our process for determining qualifying projects is detailed below. First, qualifying projects must be incremental to baseline spending amounts. We recommend that approved programs be incremental to the calculated historical capital budget and O&M budget spending before being included in the program.

As noted, based on historical capital and O&M spending for the past five years, the baseline spending of $202 million per year is reasonable. Second, we would consider the replacement of facilities or retirement of facilities that have reached their end of life to be normal reliability spending that should be done as part of baseline spending, not IIP spending through a clause. As we have noted earlier, this should be limited to projects that would not have occurred without some acceleration, not programs currently in place as part of routine operations. Third, there must be an engineering report for each proposed project. The engineering report must identify specific benefits and an applicable cost benefit analysis. Additionally, the engineering report should include project objectives, <u>specific</u> expected resiliency benefits, detailed cost estimates, cost benefit analysis, and in-service dates. The Company's broad simple project summaries do not meet the engineering report requirement as required by the regulations.[65]

Q. Based on these recommendations, do you have an adjusted infrastructure investment program?

A. Yes, we recommend a number of adjustments to the Company's proposed infrastructure investment program that is summarized below in tabular form and discussed in more detail in this section.

[65] <u>N.J.A.C</u>. 14:3-2A.5(b)(3).

Schedule 8 Summary of Rate Counsel IIP Adjustments

Program	Subprogram	Petition ($ millions)	Rate Counsel Adjusted Budget ($ millions)
Overhead Circuit Reliability and Resiliency	Lateral Fuse Replacement with TripSaver	$19.8	$0
	Enhanced Vegetation Management	$108.0	$0
	Install Back-up Generation	$5.1	$0
Substation Reliability Enhancement	Substation Enhanced Flood Mitigation	$17.8	$0
	Substation Equipment Replacement	$37.0	$0
	Mobile Substations	$8.7	$0
	Modernize Protective Equipment	$13.4	$0
	Substation Fencing Enhancement	$9.1	$0
Distribution Automation	Circuit Protection and Sectionalization	$11.5	$0
	Install SCADA - Line Devices	$45.2	$45.2
	Distribution Automation	$11.7	$11.7
	RTU Upgrades in Substations & ADMS	$40.1	$40.1
Underground System Improvements	Underground Cable Replacement	$44.9	$0
	Submersible Transformer Replacement	$3.8	$0
	Conventional and Network UG Rehab and Resiliency	$11.0	$0
Total		**$386.8**	**$97.0**

Q. Do you find the proposed IIP projects to be imprudent?

A. The determination whether any of our excluded projects are prudent should be addressed in the Company's next base rate case proceeding, should the Company include them in a future proceeding. In this proceeding, we do not assess the reasonableness or prudency of these projects. We are strictly determining whether these projects should be included in the JCP&L's IIP, and therefore subject to the special cost recovery provisions allowed under the Board's IIP Regulation.

Q. Please describe your adjustments for Circuit Reliability and Resiliency program.

A. Overall, we do not recommend including any of Circuit Reliability and Resiliency program in our adjustment to the Company's proposed IIP. All three subprograms are appropriately part of the Company's routine distribution spending to maintain reliability. We do not believe that the Company should receive accelerated recovery for routine operations to maintain its distribution system. We believe that the Company should and does undertake circuit reliability work that is prudent through its base rate mechanism.

Q. Please explain your rationale for excluding the Lateral Fuse Replacement subprogram.

A. The Lateral fuse installations and replacements have been part of Company's ongoing maintenance activities.[66] We note that the average number of lateral fuse installations have been 58, average number lateral fuse replacements have been 5,039 over the past five years (2013-2017) that includes the proposed TripSaver installations.[67] The Company has indicated that it has spent about $10 million on recloser replacements in the past five years.[68] Without the IIP, the Company will continue to install TripSavers across its service territory.

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[66] RCR-E-40, Attachment A.
[67] Ibid.
[68] Ibid.

Q. Please explain your rationale for excluding the Enhanced Vegetation Management Subprogram.

A. Notwithstanding that this subprogram will provide benefits, we exclude the subprogram because we have concerns (as detailed earlier) regarding the Company's ability to quadruple vegetation management capital spending without having the benefit of completing a trimming cycle under the 2016 Vegetation Management rules. Moreover, the Company has not estimated the increased costs associated with the proposed trimming expenses attributable to the designated Zone 2 trimming.[69]. The Company has sampled the presence of hazard trees and ash trees along circuits[70]

Q. Did you make an adjustment for the Company's Back-Up Generator Subprogram?

A. We have also eliminated the Company's subprogram for back-up generators. **[Begin Confidential]** [redacted].[71] **[End Confidential]**

Q. Please describe your adjustments for Substation Reliability Enhancement projects

A. Overall, we do not recommend including any of Substation Reliability Enhancement programs in our adjustment to the Company's proposed IIP. As we

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[69] RCR-E-63.
[70] RCR-E-38.
[71] RCR-E-122.

have noted, the Company's own benefit cost analysis found this program category not to be cost effective. All five subprograms are part of the Company's routine distribution spending to maintain reliability. We believe that the Company should and does undertake substation reliability work that is prudent through its base rate mechanism.

Q. Please explain your rationale for excluding the Substation Enhanced Flood Mitigation Subprogram.

A. The Company has noted that its temporary flood solutions have been effective.[72] The Company's describes what flood mitigation measures have been undertaken by the Company already. Flood mitigation measures have already been undertaken at 19 substations.[73] These measures included: tying distribution circuits where possible to non-flood affected substations; installing permanent walls or temporary flood barriers around specific at- risk infrastructure; monitoring substation status in real-time during events using video cameras and flood sensors; and deploying a fleet of long-run time diesel generators with high capacity pumps for specific substations to address potential water seepage around or under the permanent or temporary flood barriers. The proposed IIP enhanced flood mitigation subprogram work targets nine substations to add permanent flood walls, flood gates and pumps.[74] The proposed work references a 2013 Black and Veatch report that evaluated both permanent and temporary flood walls; raising

[72] RCR-E-6.
[73] RCR-E-6, Attachment H. Page 39.
[74] RCR-E-42. The nine substations and exact scope of work are detailed in the response to S-RP-ENG-6 Confidential Attachment A.

and relocating substations.[75] **[Begin Confidential]** [redacted] **[End Confidential]** [76] Also, as part of this subprogram, the Company is proposing to replace Portable transformers similar to projects completed in the past five years.[77]

Q. Please explain your rationale for excluding the Substation Equipment Replacement Subprogram.

A. We exclude the Substation Equipment Replacement subprogram because the Company has already undertaken the replacement of circuit breakers and switchgear equipment as part of its routine operations. In the last five years, the Company has spent over $1.3 million on just circuit breaker replacements.[78] The Company has not defined any specific prioritization criteria that would target the replacement of the identified substation equipment beyond how it normally treats the replacement of equipment.[79] Finally, it is not clear to us why the Company should receive accelerated recovery for an activity that should be part of routine maintenance.

[75] RCR-E-44 Attachment A.
[76] S-RP-ENG-6 Confidential Attachment A.
[77] RCR-E-47.
[78] RCR-E-46.
[79] RCR-E-48.

Q. Please explain your rationale for excluding the Mobile Substation subprogram?

A. We would exclude the Mobile Substation subprogram since we believe that the proposed purchase of mobile substations is not cost effective and should be part of normal capital expenditures. In the last five years, the Company has spent over **[Begin Confidential]** [redacted] **[End Confidential]** on portable units.[80]

Q. Please explain your rationale for excluding the Modernize Protective Equipment Subprogram.

A. We exclude the Modernize Protective Equipment replacement subprogram because the Company has already undertaken the replacement of substation relay equipment as part of its routine operations. In the last five years, the Company has spent over $638,000 on substation relay replacements.[81] It is not clear to us why the Company should receive accelerated recovery for an activity that should be part of routine maintenance and the Company has not articulated a prioritization process to justify the acceleration of substation relay replacements.[82]

Q. Please explain your rationale for excluding the Substation Fencing Enhancement Subprogram.

A. We exclude the Substation Fencing Enhancement Program because the Company already undertakes the installation of substation fencing across its service territory. In the last five years, the Company has spent over $400,000 on

[80] RCR-E-47 Attachment A Confidential.
[81] RCR-E-51.
[82] Ibid.

substation fencing.[83] The Company has not justified why it should receive accelerated recovery for investments that are part of routine maintenance.

Q. Please describe your adjustments for Distribution Automation projects.

A. Overall, subject to receiving detailed engineering reports, we recommend including almost all of the Distribution Automation program in our adjustment to the Company's proposed IIP since they appear cost effective. We would exclude the Company's Circuit Protection and Sectionalizing subprogram because the Company already undertakes installation of circuit protection across its service territory. In the last five years, the Company has spent over $4.5 million on circuit protection and sectionalization projects.[84] It is not clear to us why the Company should receive accelerated recovery for an activity that should be part of routine maintenance.

Q. Please describe your adjustments for Underground System Improvement Program.

A. Overall, we do not recommend including any of Underground System Improvement subprograms in our adjustment to the Company's proposed IIP. All three of the subprograms are part of the Company's routine distribution spending to maintain reliability. As we have noted, the Company's own benefit cost analysis found this category not to be cost effective.

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[83] RCR-E-52.
[84] RCR-E-53.

Q. Please explain your rationale for excluding the Underground Cable replacement subprogram.

A. We exclude the Underground Cable Replacement subprogram because the Company already undertakes the replacement of underground cable across its service territory. In the last five years, the Company has spent over $5.0 million on cable replacement projects.[85] The Company has not justified why it should receive accelerated recovery for an activity that should be part of routine maintenance.

Q. Please explain your rationale for excluding the Submersible Transformer Replacement subprogram.

A. We exclude the Submersible Transformer Replacement subprogram because the Company already undertakes the replacement of submersible transformers across its service territory. In the last five years, the Company has replaced 635 submersible transformers and has 1,248 remaining.[86] It is not clear to us why the Company should receive accelerated recovery for an activity that should be part of routine maintenance.

Q. Please explain your rationale for excluding the Conventional and Network Underground Rehabilitation and Resiliency subprogram.

A. We exclude the Conventional and Network Underground Rehabilitation and Resiliency subprogram because the Company has not experienced any outages

[85] RCR-E-58.
[86] RCR-E-59.

associated with the N-2 event that the subprogram addresses.[87] The Company notes that in the last five years, the Morristown underground ducted network has experienced two N-2 events, but neither event resulted in outages.[88] The Company's conventional ducted work appears to be routine capital spending since it addresses deteriorated and aged equipment.[89]

Q. Are there possible IIP projects that you would recommend the Board to approve?

A. Yes, we have identified $97 million of proposed projects over the four-year period that may meet our criteria for the infrastructure investment program, if supported by documentation such as detailed engineering reports, as discussed above and required by regulation. This translates to an annual JCP&L IIP spend of approximately $24.2 million. The recommended projects are all distribution automation projects that incorporate elements of advanced communications to enable remote control and operation. The Company will also need to demonstrate the cost-effectiveness, reasonableness and prudency of these selected projects in a future rate case. Moreover, these IIP projects require the Company to invest a baseline spending amount of $202 million per year <u>before</u> recovering the incremental $24.2 million per year under the IIP Regulation cost recovery mechanism.

[87] RCR-E-62.
[88] Ibid.
[89] Direct Testimony of Dennis Pagavadhi. July 13, 2018. Page 29. Lines 13-16.

Q. Please describe why you included Distribution Automation projects in your adjusted JCP&L IIP recommendations.

A. We include the Company's proposed distribution automation projects that are incremental to baseline spending since distribution automation projects are specifically referenced in the IIP Regulation.[90] However, distribution automation projects must also be integral to the distribution automation system itself and not a normal protection system or routine customer reliability expenditure. For example, a project to install an intelligent recloser that can operate in coordination with other distribution automation equipment and under the control of a distribution automation system would be included. On the other hand, a simple recloser or relay that operates independently from other devices should be excluded from the JCP&L IIP as we noted earlier in our discussion of the Company's TripSaver II program.

Q. Please summarize your adjustments to the Company's petition.

A. Our adjustments to the Company's petition are shown below.

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[90] N.J.A.C 14:3-2A.2(a).

Schedule 9 Rate Counsel Adjustments to IIP.

Program	Subprogram	Petition ($ millions)	Rate Counsel Adjusted Budget ($ millions)
Overhead Circuit Reliability and Resiliency	Lateral Fuse Replacement with TripSaver	$19.8	$0
	Enhanced Vegetation Management	$108.0	$0
	Install Back-up Generation	$5.1	$0
Substation Reliability Enhancement	Substation Enhanced Flood Mitigation	$17.8	$0
	Substation Equipment Replacement	$37.0	$0
	Mobile Substations	$8.7	$0
	Modernize Protective Equipment	$13.4	$0
	Substation Fencing Enhancement	$9.1	$0
Distribution Automation	Circuit Protection and Sectionalization	$11.5	$0
	Install SCADA - Line Devices	$45.2	$45.2
	Distribution Automation	$11.7	$11.7
	RTU Upgrades in Substations & ADMS	$40.1	$40.1
Underground System Improvements	Underground Cable Replacement	$44.9	$0
	Submersible Transformer Replacement	$3.8	$0
	Conventional and Network UG Rehab and Resiliency	$11.0	$0
Total		**$386.8**	**$97.0**

Our adjustments reduce the Company's four-year $386 million petition to $97 million and focuses the IIP to concentrate on incremental Distribution Automation spending.

Q. How do your adjustments compare with the Company's overall historical distribution budgets.

A. Our adjustments to the JCP&L IIP results in a total $97 million program, or about $24.2 million per year over the 2019-2022 period. If we take the five-year projected average of $202 million over the 2019 – 2022 period and add our recommended $24.2 million per year, this would result in an overall budget of $226 million per year for the 2019 - 2022 period.

X. CONCLUSIONS AND RECOMMENDATIONS

Q. What are your recommendations?

A. Our findings and recommendations are summarized as follows:

- We find that the majority of the proposed programs are continuation of programs already undertaken by the Company to maintain safe and reliable service and therefore should not receive accelerated recovery.
- The Company's benefit cost analysis is driven by the enhanced vegetation management subprogram. With the exception of the Distribution Automation program, the other proposed programs are not cost-effective based on the Company's own analysis on a NPV basis.
- The Company's benefit cost analysis includes elements that would overstate the benefits attributed to the proposed infrastructure investment program. **[Begin Confidential]** [redacted]. **[End Confidential]**
- There is lack of detailed engineering reports for each of the projects as required under <u>N.J.A.C</u> 14:3-2A.5(b)3. The Company's engineering report only provides broad outlines of programs and is missing individual project completion dates for some of the proposed sub-programs.

- If the Board were to proceed with approval of JCP&L's IIP, notwithstanding the identified deficiencies, we recommend that the Company approve of a four-year program of $97 million subject to the submittal of detailed engineering reports for the program. The $97 million budget reflects our adjustments to the Company's proposal removing all of the Company's proposed subprograms with the exception of the Distribution Automation program.

Q. Does this conclude your testimony?

A. Yes. However, we reserve our right to modify our testimony based on additional information provided by the Company.

ATTACHMENTS

Cape Power Systems Consulting, LLC

Charles P. Salamone P.E.

Profession: Power systems analysis and assessment, with a special emphasis on transmission planning, performance and design

Nationality: U.S. Citizen

Years of Experience: 40 years

Education B.S.E.E, Power System Engineering, 1973
Gannon University, Erie, PA

Position: Owner/Manager, Cape Power Systems Consulting

Web/Email: www.CapePowerSystems.com csalamone@capepowersystems.com

Contact Number: 774-271-0383

Summary: Mr. Salamone provides professional services based on 40 years of electric utility industry experience in the areas of Transmission Planning, Substation Planning, Distribution Planning, ISO-New England Planning Procedures, New England Power Pool Procedures, Congestion Management, Generator Interconnections, Planning/Capital Budget Management, Meter Engineering, and State (Mass DPU and New Jersey Rate Council) and Federal (FERC) Regulatory Agency Filing Development and Expert Witness Testimony

Experience:

2005- Pres. **Cape Power Systems Consulting**

Established a power system design, analysis, planning and assessment consulting company to work directly with diverse power system stakeholders.

- Worked with a number of clients for the development of analysis, reports and presentations in support of regulatory and technical review/approval process for transmission and distribution projects
- Provided technical assistance for transmission planning activities for an Independent System Operator including support for major transmission system expansion programs and development of a 10 year transmission plan
- Worked with a large Massachusetts Utility as an expert witness in support of State regulatory reviews for the siting of a major transmission system upgrade plan

- Worked with state regulatory agencies in support of electric utility rate case proceedings including expert witness testimony and assessment of electric utility performance
- Worked with multiple state regulatory agencies in support of review of electric utility smart grid initiatives including review of the technical performance, system benefits and viability of proposed electric utility programs
- Developed and conducted a comprehensive training program for implementation of an Energy Management System (EMS) based transmission system security assessment application for a large Massachusetts utility
- Worked with clients to conduct load flow assessment of transmission system performance for feasibility and reliability performance studies across New England and New York

1979-2005 NSTAR (Previously Boston Edison and Commonwealth Electric)

2000-2005 ***Director System Planning***

NSTAR (Previously Boston Edison and Commonwealth Electric) Boston, MA

- Responsible for long term planning of Company transmission, substation and distribution systems
- Successfully managed the studies, design, internal and external review and regulatory approval for a $250M 345 kV underground transmission expansion project serving the greater Boston area
- Managed numerous generator interconnection studies, design and approvals
- Successfully managed studies, design and approval for congestion mitigation plans and expansion project
- Oversaw transmission and distribution planning efforts to establish a comprehensive 10 year $300 million system expansion plan
- Served as Company representative on NEPOOL Reliability Committee and the New England Transmission Expansion Advisory Committee
- Served as Company expert witness for system planning related regulatory proceedings at both the state and federal levels.
- Supervised a staff of 10 senior engineers

1989-1999 ***Manager, System Planning and Meter Services***

Commonwealth Electric Company, Wareham, MA

- Develop risk based prioritized $10 million construction budget procedures
- Supervise a staff of 6 professional engineers and 4 analysts
- Served as chair of the NEPOOL Regional Transmission Planning Committee (currently the NEPOOL Reliability Committee)
- Process billing determinant and interval data for all major system customers
- Lead implementation of first MV90 meter data processing system
- Develop annual performance analysis reports for all transmission and major distribution systems

- Manage multiple FERC tariff based transmission customer and generation developer system impact studies
- Served as expert Company witness in State and FERC regulatory proceedings
- Implemented a risk index for prioritization of all transmission and major distribution construction projects
- Implemented automated electronic processing of major customer billing data, which significantly reduced time needed to generate bills
- Served as lead member on information technology company merger team
- Implemented process and equipment to perform all tie line, generator and wholesale customer meter testing
- Served as chair of the NEPOOL Planning Process Subcommittee, which established numerous NEPOOL policies for transmission/generator owners
- Served as Vice-Chair of the NEPOOL Reliability Committee

1984-1989 ***Meter Engineer***

Commonwealth Electric Company, Plymouth, MA

- Designed and supervised installation of 15 generator meter data recorders
- Developed customer load plotting and analysis software
- Developed meter equipment order data processing system for four remote offices
- Implemented PC control of meter test boards, which significantly reduced processing and record keeping time
- Managed programming of all electronic meter registers to insure accurate data registration

1979-1984 ***Computer Application Engineer***

Commonwealth Electric Company, Wareham, MA

- Implemented numerous technical and analytical software applications for engineering analysis
- Served as member of decision team for implementation of a new SCADA system

1978-1979 **San Diego Gas & Electric, *Planning Engineer***

San Diego Gas & Electric Company, San Diego, CA

- Performed extensive stability analysis for a new 230 kV transmission interconnection with Mexico
- Performed transmission design and performance analysis for a new 250 mile 500 kV line from San Diego to Arizona

1973-1978 **New England Gas & Electric Association, *Planning Engineer***

New England Gas & Electric Association, Cambridge, MA

- Performed extensive stability analysis for a new 560 MW generating plant on Cape Cod
- Developed transmission plan for a new 345 kV transmission line on Cape Cod
- Developed plans for design and sighting of new 115 / 23 kV substations on Cape Cod

Maximilian Chang, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 2 I Cambridge, MA 02139 I 617-453-7027
mchang@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, 2013 – present, *Associate*, 2008 – 2013.

Consults and provides analysis of technologies and policies, electric policy modeling, evaluation of air emissions of electricity generation, and other topics including energy efficiency, consumer advocacy, environmental compliance, and technology strategy within the energy industry. Conducts analysis in utility rate-cases focusing on reliability metrics and infrastructure issues and analyzes the benefits and costs of electric and natural gas energy efficiency measures and programs.

Environmental Health and Engineering, Newton, MA. *Senior Scientist*, 2001 – 2008.

Managed complex EPA-mandated abatement projects involving polychlorinated biphenyls (PCBs) in building-related materials. Provided green building assessment services for new and existing construction projects. Communicated and interpreted environmental data for clients and building occupants. Initiated and implemented web-based health and safety awareness training system used by laboratories and property management companies.

The Penobscot Group, Inc., Boston, MA. *Analyst*, 1994 – 2000.

Authored investment reports on Real Estate Investment Trusts (REITs) for buy-side research boutique. Advised institutional clients on REIT investment strategies and real estate asset exchanges for public equity transactions. Wrote and edited monthly publications of statistical and graphical comparison of coverage universe.

Harvard University Extension School, Cambridge, MA. *Teaching Assistant*, 1995 – 2002.

Teaching Assistant for Environmental Management I and Ocean Environments.

Brigham and Women's Hospital, Boston, MA. *Cancer Laboratory Technician*, 1992 – 1994.

Studied the biological mechanism of tumor eradication in mouse and human models. Organized and performed immunotherapy experiments for experimental cancer therapy. Analyzed and authored results in peer-reviewed scientific journals.

EDUCATION

Harvard University, Cambridge, MA
Master of Science in Environmental Science and Engineering, 2000

Cornell University, Ithaca, NY
Bachelor of Arts in Biology and Classics, 1992

REPORTS

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Nogee, A., M. Chang, P. Knight, E.A. Stanton. 2013. *Electricity Market Restructuring and the Nuclear Industry.* Synapse Energy Economics for Whitt Law.

Koplow, D., M. Chang. 2013. *Vogtle 3 and 4 Conditional Loan Guarantee: Review of Documents Pertaining to Department of Energy Conditional Loan Guarantees for Vogtle 3 & 4.* Synapse Energy Economics and Earth Track.

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Fagan, R., M. Chang, P. Knight, M. Schultz, T. Comings, E. Hausman, R. Wilson. 2012. *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region.* Synapse Energy Economics for Energy Future Coalition.

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Hornby, R., P. Chernick, C. Swanson, D. White, J. Gifford, M. Chang, N. Hughes, M. Wittenstein, R. Wilson, B. Biewald. 2011. *Avoided Energy Supply Costs in New England: 2011 Report.* Synapse Energy Economics for Avoided-Energy-Supply-Component (AESC) Study Group.

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TESTIMONY

New Jersey Board of Public Utilities (Docket No. ER18010029 and GR18010030): Direct testimony on Public Service Electric and Gas’ petition for base rate adjustments. On behalf of the New Jersey Division of Rate Counsel. August 6, 2018.

Illinois Commerce Commission (Docket No. 18-0211): Direct Testimony regarding Ameren Illinois Company's voltage optimization plan and the importance of prioritizing low-income communities. On behalf of the People of the State of Illinois, represented by the Office of the Illinois Attorney General. March 7, 2018.

Maryland Public Service Commission (Docket No. 9431): Direct testimony on the applications of US Wind and Skipjack Wind for the development of offshore wind projects pursuant to the Maryland Offshore Wind Energy Act of 2013. On behalf of Maryland Office of People’s Counsel. February 15, 2017.

Kansas Corporation Commission (Docket No. 16-KCPE-593-ACQ): Direct testimony on clean energy and coal fleet retirement concerns related to the petition of Great Plains Energy Inc., Kansas City Power and Light, and Westar Energy, Inc. for the acquisition of Westar by Great Plains Energy. On behalf of Sierra Club. December 16, 2016.

Maryland Public Service Commission (Docket No. 9424): Direct testimony on Delmarva Power and Light Company’s application for a rate adjustment to recover smart grid costs. On behalf of Maryland Office of People’s Counsel. October 7, 2016.

Maryland Public Service Commission (Docket No. 9418): Direct testimony on Potomac Electric Power Company's application for a rate adjustment to recover smart grid costs. On behalf of Maryland Office of People's Counsel. July 6, 2016.

Illinois Commerce Commission (Docket No. 16-0259): Direct and rebuttal testimony on Commonwealth Edison Company's annual formula rate update and revenue requirement reconciliation on distribution and business intelligence investments. On behalf of the Office of Illinois Attorney General. June 29, 2016 and August 11, 2016.

Illinois Property Tax Appeal Board (Case Nos. 12-02297, 12-01248) Direct testimony on history of nuclear deregulation in Illinois and the impact of deregulation on Exelon nuclear units. On behalf of Byron Community School District. April 2016.

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New Jersey Board of Public Utilities (Docket No. ER14030250): Direct testimony on Rockland Electric Company's petition for investments in storm hardening measures. On behalf of the New Jersey Division of Rate Counsel. September 4, 2015.

Hawaii Public Utilities Commission (Docket No. 2015-0022): Direct testimony on reliability, clean energy, competition, and management and performance concerns related to the petition of NextEra Corporation and Hawaiian Electric Companies (HECO) for the acquisition of HECO by NextEra. On behalf of the Hawaii Division of Consumer Advocacy. August 10, 2015.

Delaware Public Service Commission (Docket No. 14-193): Direct testimony evaluating the benefits and commitments of the proposed Exelon-Pepco merger. On behalf of the Delaware Department of Natural Resources. December 12, 2014.

State of New Jersey Board of Public Utilities (Docket No. EM14060581): Direct testimony on the reliability commitments filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities. On behalf of the New Jersey Division of Rate Counsel. November 14, 2014.

District of Columbia Public Service Commission (Formal Case No. 1119): Direct and answer testimony on the reliability, risk, and environmental impacts of the proposed Exelon-Pepco merger. On behalf of the District of Columbia Government. November 3, 2014 and March 20, 2015.

United States District Court District of Maine (C.A. No. 1:11-cv-00038-GZS): Declaration regarding the ability of the New England electric grid to absorb the impact of a spring seasonal turbine shutdown at four hydroelectric facilities. On behalf of Friends of Merrymeeting Bay and Environment Maine. March 4, 2013.

State of Maine Public Utilities Commission (Docket 2012-00449): Testimony regarding the Request for Approval of Review of Second Triennial Plan Pertaining to Efficiency Maine Trust. On behalf of the Maine Efficiency Trust. January 8, 2013.

New Jersey Board of Public Utilities (Docket No. GO12050363): Testimony regarding the petition of South Jersey Gas Company for approval of the extension of energy efficiency programs and the associated cost recovery mechanism pursuant to N.J.S.A 48:3-98:1. On behalf of the New Jersey Division of Rate Counsel. November 9, 2012.

RELEVANT DISCOVERY RESPONSES

I/M/O the Verified Petition of Jersey Central Power & Light Company For Approval of Infrastructure Investment Program (JCP&L Reliability Plus)

BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-93: With reference to Petition, Exhibit JC-2, Schedule DP-2 and Schedule DP-1B:

a. Please provide an explanation why the annual amounts for 2019 through 2022 shown in Schedule DP-1B do not match the corresponding Total Distribution costs shown in Schedule DP-2 for the corresponding year.

b. Please indicate if Schedule DP-2 for 2019-2022 includes the Reliability Plus program. If so, please provide electronic version with formulae intact of the schedule that differentiates the Company's proposed Reliability Plus Program from the Company's Capital Expenditure Summary for the period 2019-2022. If not, please provide a revised Schedule DP-2 in electronic format that include the Reliability Plus Program.

RESPONSE: a. The annual amounts for 2019 through 2022 shown in Schedule DP-1B for Proposed Baseline Capital do not match the Total Distribution costs shown in DP-2 for the corresponding years (*i.e.*, 2019 through 2022) for several reasons. The amounts in Schedule DP-1B for Proposed Baseline Capital ($141 million in for each year from 2019 through 2022) represent the Company's *proposal* for an annual baseline capital spending level in satisfaction of the regulatory condition in *N.J.A.C.* 14:3-2A.3(a). On the other hand, the amounts in Schedule DP-2 for 2019 through 2022 represent the Company's projected annual capital expenditure budget for that period, identified by major categories of expenditure, consistent with the minimum filing requirements set forth in *N.J.A.C.* 14:3-2A.5(b)1. Further, the Company's proposed annual Baseline Capital of $141 million in DP-1B for years 2019 through 2022 was based on a five-year average of base capital expenditures during the period 2013 through 2017, as noted in Schedule DP-1B and explained in the Direct Testimony of Mark A. Mader at pages/lines 7:12-8:2; it was not based on projections for 2019-2022. This approach is consistent with N.J.A.C. 14:3-2A.3(b) which requires the Company to provide data supporting its proposed annual baseline spending levels which may include historical capital expenditure budgets and any other data relevant to the utility's proposed baseline spending level. In addition, the Proposed Baseline Capital on Schedule DP-1B does not include all line items that are included in the Total Distribution costs for 2013-2017 on Schedule DP-2.

Mr. Mader explains in his testimony (*See* page 7, lines 15-18) that base capital excludes certain capital expenditures, such as customer requested work, storm costs and damage claims, included in the Total Other Than Base Capital on Schedule DP-2, which are uncontrollable costs for services provided on demand and/or request and, consequently, are not appropriate to include in the baseline. Thus, the Proposed Baseline Capital of $141 million for each year 2019 through 2022 in Schedule DP-1 can be matched to the average of the Total Base Capital amounts for 2013 through 2017 on the first page of Schedule DP-2.

b. Schedule DP-2 does not include costs associated with the JCP&L Reliability Plus Infrastructure Investment Program proposed for 2019 through 2022 that will be recovered through an accelerated cost recovery mechanism. The Company's base capital spending for those years, however, encompasses a matching amount of at least 10% by project category, as detailed under the heading Base Capital Similar to JCP&L Reliability Plus on Schedule DP-1B.

See RCR-E-93 Attachments A and B for revised Schedules DP-1B and DP-2 in electronic format that includes the JCP&L Reliability Plus Program. Please note that the budget for 2019 has been recently finalized. As further explanation, during the annual capital portfolio development process, the total expenditures under JCP&L's Reliability Plus program had not yet been determined. The final round of the capital portfolio process occurred after the filing of JCP&L's Reliability Plus program. Therefore, after the budget for 2019 was finalized in the capital portfolio process, JCP&L adjusted the budget accordingly to reflect the 10% matching requirements for the Reliability Plus program.

Ratio of Similar Base Capital to JCP&L Reliability Plus

Capital Baseline	2019	2020	2021	2022
Proposed Baseline Capital[1]	$141,000,000	$141,000,000	$141,000,000	$141,000,000
Base Capital Similar to JCP&L Reliability Plus[2]	**2019**	**2020**	**2021**	**2022**
Distribution Automation	$1,740,000			
Overhead Circuit Reliability and Resiliency	$3,800,000			
Underground System Improvements	$1,640,000			
Substation Reliability Enhancement	$1,730,000			
Total Base Capital Similar to IIP	$8,910,000	$10,200,000	$10,000,000	$9,600,000
IIP Capital	$89,186,659	$101,580,000	$99,610,000	$96,436,000
Base Capital to Total IIP	10%	10%	10%	10%

(1) Proposed baseline is a 5-year average of 2013 - 2017 base capital spend

(2) Company acknowledges it must maintain capital expenditures in base capital at least equal to 10% of JCP&L Reliability Plus

JCP&L Capital Expenditure Summary 2013-2022
Identified By Major Categories

	2013	2014	2015	2016	2017
Metering	3,511,323	9,557,573	8,684,953	6,353,165	$5,227,588
Other	26,614,703	11,741,883	21,596,120	2,236,139	$6,282,655
Replacements & Improvements	$41,790,206	$77,918,555	$69,752,522	$69,740,591	$70,218,984
Vegetation Management	$7,264,569	$14,075,284	$13,251,603	$12,447,966	$12,777,019
Reliability	$12,628,563	$32,815,760	$25,092,479	$25,598,458	$17,093,356
Street Lighting	$6,537,720	$7,418,273	$6,155,755	$5,980,031	$6,177,456
System Reinforcements	$6,936,747	$13,351,075	$8,710,174	$7,067,841	$6,572,484
Facilities	$471,848	$880,785	$2,362,541	$2,178,677	$9,653,947
Tools & Equipment	$1,472,189	$4,566,009	$3,745,250	$1,716,197	$2,548,511
Total Base Capital	$107,227,868	$172,325,199	$159,351,397	$133,319,066	$136,552,001
Damage Claims	$6,610,309	$8,878,243	$3,758,234	$5,095,480	$4,531,516
Joint Use	$318,686	$1,959,592	$2,668,493	$1,644,550	$519,163
New Business	$20,700,005	$38,228,291	$36,127,765	$42,018,410	$37,721,964
Relocations	$4,578,829	$545,995	$2,483,689	$2,172,469	$1,931,381
Storms	$23,574,103	($13,212,557)	$1,402,760	$22,429,556	$9,751,141
Total Other Than Base Capital	$55,781,933	$36,399,564	$46,440,941	$73,360,465	$54,455,164
Total Distribution	$163,009,800	$208,724,763	$205,792,337	$206,679,531	$191,007,165

I/M/O the Verified Petition of Jersey Central Power & Light Company
For Approval of Infrastructure Investment Program (JCP&L Reliability Plus)

BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

S-JCP&L-INF-10	Provide a breakdown of the $108 million for vegetation management. Specifically, how much will be for zone 2 overhang, ash trees, and hazard trees.
RESPONSE:	*See* JCP&L's Response to S-JCP&L-INF-10 Attachment A.

Year	Cost of Ash Removal	Cost of Hazard Tree Removal	Zone 2 Overhang Removal	Totals
2019	$ 10,789,094	$ 5,385,130	$ 11,570,081	**$ 27,744,306**
2020	$ 10,538,568	$ 5,219,708	$ 12,530,061	**$ 28,288,338**
2021	$ 10,773,295	$ 5,150,912	$ 10,189,153	**$ 26,113,361**
2022	$ 10,594,326	$ 4,819,338	$ 10,456,227	**$ 25,869,891**
Totals	**$ 42,695,284**	**$ 20,575,089**	**$ 44,745,523**	**$ 108,015,896**

I/M/O the Verified Petition of Jersey Central Power & Light Company For Approval of Infrastructure Investment Program (JCP&L Reliability Plus)

BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-72: With reference to page 12 of the JCP&L Reliability Plus Engineering Evaluation and Report attached to Mr. Pavagadhi's Direct Testimony, please provide:

a. The annual number of hazard trees removed in the last five years;

b. The annual number of Ash trees removed in the last five years; and

c. Any studies commissioned or produced by the Company regarding hazard trees and/or emerald ash borer infestation.

RESPONSE:

a. *See* RCR-E-72 Attachment A.

b. JCP&L did not begin tracking Ash tree removals until 2017. *See* RCR-E-72 Attachment A.

c. JCP&L has referred to the Emerald Ash Borer ("EAB") Detection Report, last updated on June 27, 2018, provided by the New Jersey Department of Agriculture,[1] for tracking the spread of EAB in New Jersey.

[1] See: **https://www.nj.gov/agriculture/divisions/pi/prog/emeraldashborer.html**

Year	Ash Tree Removals (a)	Hazard Tree Removals (b)
2013	-	1,525
2014	-	5,332
2015	-	6,098
2016	-	5,773
2017	700	6,602
2018 YTD	5,515	3,836

§ 14:5-8.7 (b) 7. Ten years of trends reflecting the major causes of interruptions

The following table and graph provide the ten year trend data for the major causes of interruptions for the JCP&L service territory as a whole over the 10 years prior to the submittal of this report.

JCP&L[a,b]								
Year	Animals	Equipment Related[c]	Lightning Related	Other / Unknown	Trees Non Prev.[d]	Trees Prev.[e]	Vehicle	Total
2010	204,346	1,003,618	61,313	347,903	670,393	14,252	115,175	2,417,000
2009	97,491	625,712	148,613	251,536	659,283	8,182	101,182	1,891,999
2008	117,507	636,121	130,127	345,223	423,619	13,091	121,312	1,787,000
2007	126,680	673,993	367,636	385,403	426,731	9,317	133,240	2,123,000
2006	201,694	1,089,522	246,099	700,973	567,497	33,597	171,618	3,011,000
2005	187,135	790,893	241,787	1,095,749	461,786	123,499	237,151	3,138,000
2004	227,709	681,797	448,531	705,664	348,998	82,715	212,587	2,708,001
2003	226,537	821,929	218,750	1,391,487	578,768	91,232	140,297	3,469,000
2002	285,282	562,782	461,714	917,355	713,801	111,634	111,432	3,164,000
2001	280,731	557,456	404,256	744,750	276,805	72,712	152,291	2,489,001
Total	1,955,112	7,443,823	2,728,826	6,886,043	5,127,681	560,231	1,496,285	26,198,001

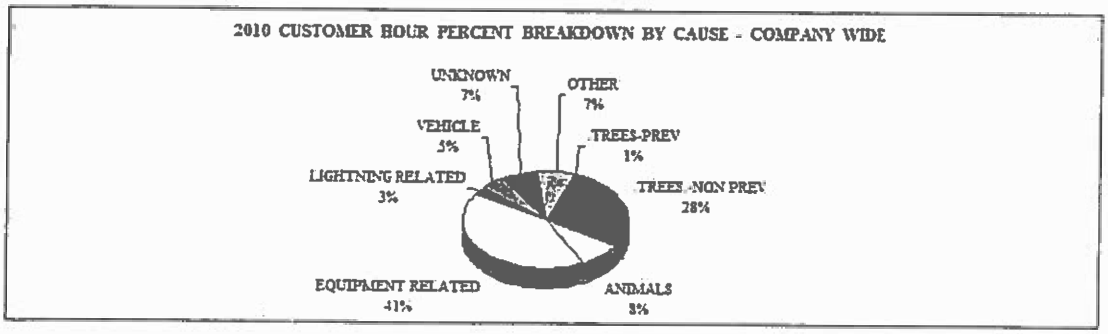
[a] All outage trend data is based on a sustained interruption being defined as an interruption with a duration greater than 5 minutes.

[b] All trend data are shown in customer hours.

[c] Equipment related interruptions include phase-to-phase or phase-to-ground fault except those that occur when lightning is indicated on the outage report as the predominant element of weather.

[d] Trees Non Prev. – Refers to non-preventable tree related incidents, for instance, an outage caused by a tree or tree limb(s) that falls or is blown into a Company line (usually due to wind, storm or an accident).

[e] Trees Prev. – Refers to preventable tree related incidents, for instance, an outage caused by a tree that has grown into and contacted a Company line.



EXCERPT

§ 14:5-8.8 (c) 7. Technology initiatives to improve reliability

Automatic Circuit Tie Schemes[3] – As of the end of 2017, JCP&L has seventy-one (71) automatic distribution circuit tie schemes in place.[4] Such circuit tie schemes automatically transfer customers to an adjacent circuit in the event of a circuit lockout, which helps to reduce the number of customers affected from a sustained outage. Please note that each automatic circuit tie scheme typically involves two (2) different circuits. By the end of 2017, the Company had completed implementation of forty-four (44) fully functional SCADA-enabled automatic circuit tie schemes with plans to identify more high-value locations for new automatic circuit tie schemes in 2018.

Adaptive Relaying Strategy – As reported in earlier reports, during 2007, the Company began the deployment of its adaptive relaying strategy. This technology allows the dispatcher to selectively place the protective relaying schemes on Company circuits into either the normal "Fuse Sacrifice" or storm "Fuse Save" mode of operation. The purpose of the normal operational mode is to reduce the impact of outage events by limiting the number of customers that experience an interruption event to those downstream from a distribution line fuse. This prevents a substation breaker from locking open for a permanent line fault. Conversely, during storm events where wind and/or lightning make temporary faults more likely, selecting the "Fuse Save" mode of operation prevents larger numbers of sustained outages in favor of more frequent but momentary outages. The technology was fully deployed during the first half of 2008. The Company continues to use the technology deployed in connection with this strategy.

Substation Flood Mitigation

During 2017, JCP&L completed its flood mitigation project at nineteen JCP&L substations identified as 'at risk' for flooding based on historical events. The project was, and is, guided by the principles of service continuity, equipment protection, capable of being constructed in a timeline to avoid exposure over multiple hurricane seasons, and cost-effective risk mitigation. The Company conducted a site specific review, analysis and planning to more precisely address the actual and experienced risk presented at each location in a cost-effective and efficient manner. The plan developed by JCP&L employed the following strategies:

- Tying distribution circuits where possible to non-flood affected substations;
- Installing permanent walls or temporary flood barriers around specific at- risk infrastructure;

[3] In accordance with the Schumaker & Company Management Audit Report Recommendation V-1, beginning in 2013, JCP&L began reporting on the number of circuits on which tie and recloser schemes have been implemented during the past year as part of the Annual System Performance Report.

[4] Of these seventy-one (71), forty-four (44) also have SCADA control. Plans for installing SCADA control on the remaining twenty-seven (27) circuit tie schemes that do not yet have SCADA control are progressing.

**I/M/O the Verified Petition of Jersey Central Power & Light Company
For Approval of Infrastructure Investment Program (JCP&L Reliability Plus)**

BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-37: With reference to page 19 of Mr. Pavagadhi's Direct Testimony on lines 10-11, please provide:

a. The Company's annual budget and spending on vegetation management for the last eight years;

b. The miles trimmed and inspected for the last eight years.; and

c. Expected impact of the project on reduction in outages, SAIFI and CAIDI resulting from the proposed Enhanced Vegetation Management Program.

RESPONSE: JCP&L objects to this request on the grounds that it seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence, is overbroad and is unduly burdensome. Subject to and without waiving this objection, the following response addresses the time period of 2013 through 2017.

a. Refer to Schedule DP-2 of the Direct Testimony of Dennis Pavagadhi for the capital spending on vegetation management for the period 2013 through 2017. *See* RCR-E-37 Attachment A for the capital budget for vegetation management for the period 2013 through 2017.

b. *See* RCR-E-37 Attachment B.

c. The Enhanced Vegetation Management Project is targeted to reduce the number of tree-related outages during both blue sky and storm conditions caused by falling trees and limbs for the circuits where work is proposed under this program. To conduct the Cost-Benefit Analysis ("CBA"), JCP&L has estimated the benefits for each project-type for each circuit where a project is proposed under the JCP&L Reliability Plus programs, based on historical performance, using the previous 5 years of outage data (2013-2017). The estimated reductions in CMI, which is the total outage minutes customer experience and CI, which is the total number of customers that experience an outage, were translated into post-project SAIFI and CAIDI estimates, which were inputs to the Department of Energy ("DOE") Interruption Cost Estimate ("ICE") tool. The ICE tool was then used to quantify the dollar benefits based on a reduction in historical outages from a proposed project. This approach is discussed in the Engineering Evaluation and Report attached as Appendix B to the Direct Testimony of Dennis Pavagadhi at pages 28-29.

The estimate of benefits from the CBA is for the purpose of providing a comparative economic analysis and is not intended to forecast or predict future reliability performance for its circuits where projects are proposed or for the distribution system overall. Reliability performance is largely influenced by factors that are difficult to predict, the most difficult being weather in any given year. Circumstances beyond JCP&L's control (*e.g.* weather, vehicle accidents, animal-caused outages, etc.) may impact future reliability performance when compared to the calculated reliability improvements.

See also JCP&L's Response to RP-ACC-4 CONFIDENTIAL Attachment A, for the Company's cost benefit analysis calculations including inputs.

Year	Capital Budget for Vegetation Management
2013	$7,264,569
2014	$14,075,284
2015	$13,251,603
2016	$12,447,966
2017	$14,806,484

Year	Miles Trimmed[1]	Miles Inspected[1]
2013	3,149	3,149
2014	3,035	3,035
2015	2,821	2,821
2016	2,997	2,997
2017	3,150	3,150

Notes

[1] The above chart shows the "planned" or" targeted" miles that were inspected, and trimmed (as necessary) by year. Please note that VgMS tracks circuit mileage, as well as the date work is started and completed. Please further note, that as explained in the 2011 ASPR, and in the 2012 Base Rate Case testimony, a certain limited amount of vegetation management work was deferred for completion in a subsequent cycle year and was mostly completed by December 31, 2011 with a small amount of remaining work deferred into 2012 due to the impact of Hurricane Irene and the October 2011 snowstorm. These deferrals were tracked manually by the JCP&L Vegetation Management Department and were completed during the first quarter of 2012.

I/M/O the Verified Petition of Jersey Central Power & Light Company For Approval of Infrastructure Investment Program (JCP&L Reliability Plus)

BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-95: With reference to the response to RCR-E-37:

a. Please indicate if the Company's proposed Enhanced Vegetation Management program will supplant the Company's existing vegetation management program. If not, please provide the Company's baseline vegetation management annual budgets for 2019-2022.

b. Please indicate if the Company's current vegetation management program meets N.J.A.C. 14:5-9.1. If not, please explain why not.

c. Please indicate if the Company's enhanced vegetation management program exceeds N.J.A.C. 14:5-9.1. If so, please explain. If not, please explain why not.

RESPONSE:

a. No. The Enhanced Vegetation Management project will be in addition the existing vegetation management program. Refer to Schedule DP-2 of the Direct Testimony of Dennis Pavagadhi for the projected annual capital budgets for vegetation management for 2019 through 2022.

b. The Company's current vegetation management program meets N.J.A.C. 14:5-9.1.

c. Yes, the Company's Enhanced Vegetation Management project exceeds N.J.A.C. 14:5-9.1. As described in more detail in the Engineering Evaluation and Report:

   1. Ash trees will be removed given their high mortality rate whether or not they pose an immediate threat to JCP&L's equipment,
   2. Hazard trees will be removed on a targeted, accelerated basis above and beyond the work performed in the standard four-year trimming cycle; and
   3. Overhang removal will be performed on selected circuits in zone 2.

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<u>RESPONSE TO DISCOVERY REQUEST</u>

S-JCP&L-INF-14 Please provide historical O&M for Vegetation Management for 2013 through 2018.

RESPONSE: *See* the table below. In the BPU's Order in JCP&L's 2012 base rate case (BPU Docket No. ER12111052 and OAL Docket No. PUC16310-12), the BPU provided that "The Board believes it would be appropriate to allow the Company to use deferred cost accounting for all forestry maintenance expenses that exceed 105 percent of the actual expenses reported above the historical average found by the ALJ to be reasonable, and HEREBY AUTHORIZES the Company to do so."

	2013A	2014A	2015A	2016A	2017A
JCP&L O&M Distribution Forestry	$ 12,170,512	$ 9,211,420	$ 10,676,172	$ 9,662,687	$15,462,350
VMS Deferral	$ -	$ -	$ (654,409)	$ (439,411)	$ (3,239,197)
JCP&L O&M Forestry Net of Deferral	$ 12,170,512	$ 9,211,420	$ 10,021,763	$ 9,223,276	$12,223,153

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BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-63: With reference to page 30 of Mr. Pavagadhi's Direct Testimony on lines 5 through 7: please indicate if the Company has estimated the associated increased vegetation management costs. If so, please provide a copy. If not, please explain why not.

RESPONSE: JCP&L has not yet estimated the associated increased vegetation management costs for maintaining the Zone 2 clearing corridor in the future. These estimates would not be made until the year prior to routine maintenance trimming, which routine maintenance trimming, based on JCP&L's current vegetation management cycle, would not occur until four years following the JCP&L Reliability Plus Enhanced Vegetation Management project work.

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RESPONSE TO DISCOVERY REQUEST

S-JCP&L-RP-ACC-10 Please provide the Company's vegetation management expenditures over that past 10 years. Does the Company anticipate a reduction in enhanced vegetation cost over the life of the program? Will the Company implement a cost control mechanism for this project?

RESPONSE: The Company objects to this interrogatory to the extent it seeks more than five years of historical information on the grounds that it seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence and is overbroad. Subject to and without waiving the foregoing objection, *see* JCP&L's response to RCR-E-37-part a for the past 5 years of vegetation management capital expenditures.

JCP&L does not anticipate a reduction in cost to the JCP&L Reliability Plus Enhanced Vegetation program over its 4-year life.

The Company plans to implement similar cost and quality control procedures and mechanisms as it does with its normal cycle trim. The control measures include full inspections of all work performed by contractors and audits of all invoices.

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<u>RESPONSE TO DISCOVERY REQUEST</u>

S-JCP&L-RP-ACC-4 Please provide the excel calculations for the cost/benefit analysis for both nominal and Net Present value (NPV) with all formulae intact.

RESPONSE: *See* S-JCP&L-RP-ACC-4 CONFIDENTIAL Attachment A.

S-JCP&L-RP-ACC-4 CONFIDENTIAL Attachment A is an Excel Spreadsheet that is too large to send via e-mail. Therefore, an electronic copy of the attachments to this response will be provided on computer disc ("CD") to the limited distribution list shown below using an overnight delivery service.

- **BPU Staff:** Stacy Peterson
- **DAG:** Alex Moreau
- **Rate Counsel:** Celeste Clark
- **Rate Counsel Consultants:**
  - Max Chang
  - Charles Salamone
  - David Peterson
  - Kevin W. O'Donnell, CFA

Additional CDs can be furnished upon request.

Year	Recloser Installations (c)	Recloser Installation Costs (d)	Lateral Fuse Replacements (f)
2013	72	$ 2,089,498.16	4,798
2014	99	$ 2,606,961.66	5,189
2015	53	$ 2,960,460.00	3,769
2016	37	$ 655,014.27	6,079
2017	28	$ 1,742,052.40	5,362

I/M/O the Verified Petition of Jersey Central Power & Light Company For Approval of Infrastructure Investment Program (JCP&L Reliability Plus)

BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-38: With reference to page 19 of Mr. Pavagadhi's Direct Testimony on lines 11-14, please indicate if the Company has undertaken an assessment of weakened tree conditions under the proposed enhanced vegetation management program. If so, please provide a copy. If not, please explain why not.

RESPONSE: JCP&L foresters have investigated a statistically significant sample of the 2019 Reliability Plus Enhanced Vegetation Management circuits to ascertain the scope of hazard and Ash trees. Of the 364 miles surveyed, there was a count of 8,521 Ash trees and 1,043 hazard trees.[1]

[1] While these values represent the raw count of Ash trees and hazard trees, a further evaluation would occur to assess which trees pose the highest risk to reliability. In addition, some of these trees are located on private property for which JCP&L would need permission to remove or trim.

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BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-42: With reference to page 22 of Mr. Pavagadhi's Direct Testimony on lines 8-9, please:

a. Identify the nine substations that were impacted by flood events;
b. Provide details the damage and restoration costs associated with each flood event;
c. Indicate if the substation interrupted service, if so please provide the number of customers impacted and the duration of the impact for each flooding event; and
d. Indicate if the Company had pumps on hand at the affected substation for each flooding events.

RESPONSE:

a. A total of 18 substations have previously flooded, which includes the nine referenced substations identified for enhanced storm hardening in JCP&L Reliability Plus as set forth in the Confidential Engineering Schedules (at pages 133-134) to the Engineering Evaluation and Report that is Appendix B to the Direct Testimony of Dennis Pavagadhi. *See* JCP&L's Response to RCR-E-20. *See also* JCP&L's Response to RP-ENG-6 CONFIDENTIAL Attachment A.

b. The damages that occurred during Hurricane Irene and Superstorm Sandy included: damaged switchgear, breakers, relays, and control wiring. *See* RCR-E-42 CONFIDENTIAL Attachment A for the costs associated with the flooding repairs. These costs do not include initial troubleshooting, investigation and restoration work that is typically charged to the major storm order during the event. Once it is determined what specific equipment is damaged and must be replaced, specific orders are created and those are the costs captured above in this response.

c. During Hurricane Irene three of the nine substations were impacted and service was interrupted to all customers fed from the substation. During Hurricane Sandy five of the nine substations were impacted, and all customers fed from those substations experienced an outage. The duration of the outage directly attributable to flooding is difficult to determine since there were a multitude of other issues that also resulted in outages. *See* RCR-E-42 CONFIDENTIAL Attachment A for the number of customers affected by the substation outages as well as the total customer minutes interrupted in both Hurricane Irene and Superstorm Sandy.

d. Pumps were not on hand at any of the nine substation sites for the flooding events.

SUBSTATION FLOOD PROTECTION

Summary Report

B&V PROJECT NO. 179317

PREPARED FOR

FirstEnergy

Jersey Central Power & Light

28 MAY 2013

BLACK & VEATCH
Building a world of difference.

**I/M/O the Verified Petition of Jersey Central Power & Light Company
For Approval of Infrastructure Investment Program (JCP&L Reliability Plus)**

BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-47: With reference to page 23 of Mr. Pavagadhi's Direct Testimony on lines 5-6, please:

a. Indicate the annual amount spent on portable distribution station transformer units in the past five years;

b. Indicate the number of portable distribution system transformer units are currently in-service;

c. Indicate the annual number of substations that the Company has performed portable distribution system transformer unit upgrades; and

d. Please describe and provide supporting documentation for the Company's planning criteria to justify the portable distribution system transformer unit upgrades.

RESPONSE:

a. *See* RCR-E-47 CONFIDENTIAL Attachment A.

b. JCP&L has six portable distribution system transformer units currently in service.

c. JCP&L has not performed any portable distribution system transformer upgrades.

d. The portable distribution system transformer units were designed as self-contained portable distribution substations. This type of equipment is non-standard and is no longer supported by the manufacturer. As components fail, it results in a lengthy process to secure replacements, and at times, parts have been taken from one unit to the next. Additionally, JCP&L does not have any spares of these type units. A failure of this equipment could result in the need to replace the unit with a standard modular sub on an unplanned basis. The transformers in these portable distribution system units are rated at 12 MVA and have no overload capability. The standard JCP&L modular substation (consisting of modular transformers and circuit breakers) has a transformer rated at 14 MVA with an overload capability of 25%, which would give these locations up to an approximate 45% increase in capacity that could be leveraged for other initiatives, such as distribution automation.

Refer also to the Engineering Evaluation and Report that is Appendix B to Mr. Pavagadhi's Direct Testimony at page 17.

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BPU Docket No. EO18070728

<u>RESPONSE TO DISCOVERY REQUEST</u>

RCR-E-46: With reference to page 23 of Mr. Pavagadhi's Direct Testimony on lines 3-4, please:

a. Indicate the annual amount spent on circuit breaker upgrades in the past five years;

b. Indicate the annual number of substations that the Company has performed circuit breaker upgrades; and

c. Describe and provide supporting documentation for the Company's planning criteria to justify circuit breaker upgrades.

RESPONSE:

a. *See* RCR-E-46 Attachment A. In addition to the dollars spent upgrading circuit breakers, over the past five years $1.7 million was spent maintaining distribution breakers and switchgear.

b. Distribution circuit breakers were replaced in 18 substations over the last five years.

c. Circuit breakers and switchgear are treated similarly to other electrical components on the distribution system and are replaced if the equipment was no longer serviceable, was damaged or deteriorated beyond repair, was forecasted to operate more than its current carrying or fault interrupting ratings, or needed to be replaced as part of a voltage conversion project and the equipment was not rated for the planned voltage rating of the new system.

Refer also to the Engineering Evaluation and Report that is Appendix B to Mr. Pavagadhi's Direct Testimony at page 21.

Year	Amount Spent on Circuit Breaker Upgrades	
2013	$	-
2014	$	721,820
2015	$	231,172
2016	$	149,441
2017	$	242,433

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BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-48: With reference to page 23 of Mr. Pavagadhi's Direct Testimony on lines 6-7, please:

a. Indicate the annual amount spent on substation switchgear replacements in the past five years;
b. Indicate the number of oil-filled switchgear breakers are currently in-service;
c. Indicate the in-service dates and failure rate of the switchgear breakers that are to be replaced;
d. Indicate the annual number of substations that the Company has performed switchgear replacements; and
e. Please describe and provide supporting documentation for the Company's planning criteria to justify the replacement of switchgear.

RESPONSE:

a. *See* RCR-E-48 Attachment A.
b. JCP&L does not have any oil-filled switchgear breakers in its service territory.
c. JCP&L does not specifically track the failure of substation switchgear breakers. *See* RCR-E-48 CONFIDENTIAL Attachment B for the in-service dates of the switchgear breakers that are to be replaced.
d. JCP&L has performed switchgear replacements at seven substations over the last five years.
e. Circuit breakers and switchgear are treated similarly to other electrical components on the distribution system and would be replaced if the equipment was no longer serviceable, was damaged or deteriorated beyond repair, was forecasted to operate in excess of its current carrying or fault interrupting ratings or needed to be replaced as part of a voltage conversion project and the equipment was not rated for the planned voltage rating of the new system.

Refer also to the Engineering Evaluation and Report that is Appendix B to Mr. Pavagadhi's Direct Testimony at page 17.

Year	Amount Spent on Switchgear Replacements	
2013	$	216,156
2014	$	36,352
2015	$	222,234
2016	$	547,539
2017	$	1,488,904

**I/M/O the Verified Petition of Jersey Central Power & Light Company
For Approval of Infrastructure Investment Program (JCP&L Reliability Plus)**

BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-51: With reference to page 24 of Mr. Pavagadhi's Direct Testimony on lines 4-6, please:

a. Indicate the annual amount spent on substation relay replacements in the past five years;
b. Indicate the annual number of substations that the Company has performed relay replacements;
c. Indicate in-service dates and failure rate of relays to be replaced;
d. Indicate the number ABB distribution protection unit and Underfrequency Load Shed type relays currently in service; and
e. Please describe and provide supporting documentation for the Company's planning criteria to justify the replacement of relays.

RESPONSE:

a. *See* RCR-E-51 Attachment A.
b. JCP&L has replaced distribution relays at 32 substations from 2013 through 2017.
c. The specific age of the relays is not available in plant accounting records. The relay equipment nameplate should contain the manufacturing date; however, the nameplate is generally located on the back of the relay covered by the relay panel such that it is not accessible or to access the relay could put the system at risk and lead to a mis-operation due to vibration. JCP&L does not specifically track the failures of substation relays.
d. JCP&L has 272 distribution Underfrequency Load Shed type relays and 94[1] Distribution Protection Unit relays in service.
e. Distribution relays are treated similarly to other electrical components on the distribution system and would be replaced if the equipment was no longer serviceable, was damaged or deteriorated beyond repair, was forecasted to operate more than its current carrying or fault interrupting ratings, or needed to be replaced as part of a voltage conversion project and the equipment was not rated for the planned voltage rating of the new system.

Refer also to the Engineering Evaluation and Report that is Appendix B to Mr. Pavagadhi's Direct Testimony at page 19.

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[1] 87 of these relays will be replaced as a part of JCP&L Reliability Plus and the remaining seven relays will be replaced in JCP&L's baseline budget.

Year	Amount Spent on Substation Relay Replacements	
2013	$	49,540
2014	$	172,014
2015	$	131,981
2016	$	96,085
2017	$	188,229

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BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-52: With reference to page 24 of Mr. Pavagadhi's Direct Testimony on lines 20-22, please:

a. Indicate the annual amount spent on substation perimeter fencing in the past five years;
b. Indicate the annual number of substations that the Company has replaced perimeter fencing;
c. Indicate the number of substation in service;
d. Indicate the number of substation that the Company require new perimeter fencing;
e. Indicate the annual number of unauthorized intrusions at substations; and
f. Please describe and provide supporting documentation for the Company's planning criteria to justify the new perimeter fencing.

RESPONSE:

a. JCP&L has not replaced full perimeter fencing in the past five years, however, JCP&L has incurred costs to repair portions of substation fencing. *See* RCR-E-52 Attachment A.
b. *See* the response to part a.
c. JCP&L has 327 substations in service.
d. JCP&L has determined that 56 electric distribution substations should be provided with enhanced fencing in JCP&L Reliability Plus. *See* Confidential Schedules to Engineering Evaluation and Report that is Appendix B to the Testimony of Dennis Pavagadhi at pages 161-164.
e. JCP&L has experienced 111 unauthorized intrusions at substations over the past five years.
f. Refer to the Engineering Evaluation and Report that is Appendix B to Mr. Pavagadhi's Direct Testimony at page 20.

Year	Amount Spent on Substation Fencing	
2013	$	81,931
2014	$	132,481
2015	$	143,034
2016	$	42,837
2017	$	23,088

**I/M/O the Verified Petition of Jersey Central Power & Light Company
For Approval of Infrastructure Investment Program (JCP&L Reliability Plus)**

BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-53: With reference to page 25 of Mr. Pavagadhi's Direct Testimony on lines 7-10, please:

a. Indicate the annual amount spent on distribution automation in the past five years;
b. Indicate the annual number of feeders that the Company has installed distribution automation devices; and
c. Indicate the number of feeders without distribution automation devices.

RESPONSE:

a. *See* RCR-E-53 Attachment A.

b. *See* RCR-E-53 Attachment B.

c. Approximately 1,075 feeders are not equipped with distribution automation at this time.

Year	Amount Spent on Distribution Automation
2013	$ 517,551
2014	$ 1,826,267
2015	$ 1,154,055
2016	$ 274,514
2017	$ 688,454

Year	Installation of Distribution Automation in Number of Feeders
2013	14
2014	46
2015	38
2016	8
2017	12

**I/M/O the Verified Petition of Jersey Central Power & Light Company
For Approval of Infrastructure Investment Program (JCP&L Reliability Plus)**

BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-58: With reference to page 28 of Mr. Pavagadhi's Direct Testimony on lines 4-5, please, provide:

a. The amount of underground cable currently in-service;
b. The amount of underground cable with pre-1986 construction currently in-service;
c. Indicate the failure rates/repairs associated with underground cable to be replaced;
d. Indicate the annual amount spent on underground cabling replacement in the past five years; and
e. Supporting documentation for the Company's planning criteria to justify the replacement of bare neutral underground cable.

RESPONSE:

a. JCP&L has approximately 9,150 underground distribution conductor miles currently in service.
b. JCP&L estimates that 54% (approximately 4,900 distribution conductor miles) of underground distribution conductor is Bare Concentric Neutral ("BCN"). BCN cable was the typical underground distribution conductor installed prior to 1986.
c. Between 2012 and 2017, there were approximately 130 cable failures on the underground cable proposed to be replaced in JCP&L Reliability Plus.
d. *See* RCR-58 Attachment A.
e. *See* RCR-E-58 CONFIDENTIAL Attachment B, as well as the Engineering Evaluation and Report that is Appendix B to Mr. Pavagadhi's Direct Testimony at page 26.

Year	Amount Spent on Underground Cable Replacement	
2013	$	870,990
2014	$	1,452,262
2015	$	492,219
2016	$	1,174,887
2017	$	1,046,090

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BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-59: With reference to page 28 of Mr. Pavagadhi's Direct Testimony on lines 13 and 14, please, provide:

a. The annual amount spent on submersible transformer replacements in the past five years;

b. The annual number of submersible transformer replacements in the past five years; and

c. The number of submersible transformers currently in-service.

RESPONSE:

a. JCP&L does not track spend specifically for submersible transformer replacements since these replacements are normally completed as a part of a larger project.

b. *See* RCR-E-59 Attachment A.

c. There are approximately 1,248 single phase submersible transformers in-service at JCP&L.

Year	Submersible Transformer Replacements
2013	136
2014	82
2015	169
2016	119
2017	129

I/M/O the Verified Petition of Jersey Central Power & Light Company For Approval of Infrastructure Investment Program (JCP&L Reliability Plus)

BPU Docket No. EO18070728

RESPONSE TO DISCOVERY REQUEST

RCR-E-62: With reference to page 29 of Mr. Pavagadhi's Direct Testimony on lines 8 through 11, please provide:

a. Copies of PJM or JCPL planning criteria supporting the need for N-2 contingencies;

b. Details associated with all N-2 events impacting the Morristown underground network in the last five years;

c. Details associated with all outage events impacting the Morristown underground network in the last five years; and

d. The locations of any other underground network within the Company's service territory or in New Jersey that has been built to an N-2 contingency.

RESPONSE

a. PJM does not have planning criteria in relation to N-2 contingencies specific to distribution systems. The FirstEnergy/JCP&L planning criteria does not specifically discuss the need for N-2 redundancy in underground network systems.

b. Since 2013, there have been two N-2 events impacting the Morristown underground ducted network system. On June 13, 2018, there was a switch failure inside the substation impacting three circuits. On August 8, 2018 there were two primary network feeders deenergized, one due to a dig in, and the other due to a cable failure. Because of system loading conditions at the time, neither of these events resulted in outages.

c. *See* RCR-E-62 Attachment A.

d. There are no other locations of underground ducted networks within the Company's service territory. The Company does not have knowledge of whether or not there are locations of non-JCP&L underground networks within the State of New Jersey that have been built to full N-2 redundancy. In addition to the underground ducted network located in Morristown, the Company has conventional ducted distribution systems located underground in Summit, Pompton Lakes, Parsippany, Asbury Park, Allenhurst, Elberon and Morristown. *See* Confidential Schedules to Engineering Evaluation and Report that is Appendix B to the Direct Testimony of Dennis Pavagadhi at pages 285-286.

Date	Morristown Network Outages	Customers Impacted
1/9/2014	Damaged service from road salt in manhole 43 (part power Presbyterian Church)	1
2/18/2014	On court Street parking deck; fire pump with a large chunk of salt on crab (part power- made new connection)	1
12/1/2014	Burnt hot leg coming from manhole 84 near vault 560 on Speedwell Ave	1
4/20/2015	Failed service going to Market Street	3
6/21/2016	Two phase fault (Police Department)	1
4/27/2017	Fault in manhole 170 (Police Department)	1
6/26/2018	Part power at Rico Pan Bakery on Early Street	1
8/2/2018	Secondaries swapped to another circuit (Police Department)	1
8/7/2018	Fault in manhole 154 on South and Dehart (Police Department)	1
9/10/2018	Failed service (Morristown Diner)	1